BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2016-2537349

2016 GENERAL BASE RATE FILING

(Volume III of III)

FILED: April 28, 2016

METROPOLITAN EDISON COMPANY

TABLE OF CONTENTS & INDEX OF FILING REQUIREMENTS

Volume I

Metropolitan Edison Company Exhibit No. 1 – Supplement No. 23 to Tariff Electric – Pa. P.U.C. No. 52

Statement No. 1 – Direct Testimony of Charles V. Fullem

Statement No. 2 – Direct Testimony of Richard A. D'Angelo

Exhibit	FR	Description
Exhibit RAD-3		Rate Base at Original Cost Normalized to Year-End Conditions at December 31, 2016
Exhibit RAD-4		Statement of Operating Income, 12 Months Ended December 31, 2017, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
Exhibit RAD-5		Rate Base at Original Cost Normalized to Year-End Conditions at December 31, 2015
Exhibit RAD-6		Statement of Operating Income, 12 Months Ended December 31, 2015, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
Exhibit RAD-7 **(Highly Confidential)**[1]	I-B-3	Transmission System Map
Exhibit RAD-8	II-A-1	Test Year Rate Base and Rates of Return – Future
Exhibit RAD-9	II-A-2	Test Year Rate Base and Rates of Return – Historic
Exhibit RAD-10	II-A-3	Generation Cost Information
Exhibit RAD-11	II-B-1	Plant Held for Future Use
Exhibit RAD-12	II-B-2	Construction Work In Progress
Exhibit RAD-13	II-B-3	Claim for Materials and Supplies
Exhibit RAD-14	II-B-4	Cash Working Capital Claim

[1] Exhibit RAD-7 is **Highly Confidential** and is being provided to the Commission in hard copy only.

Exhibit	FR	Description
Exhibit RAD-15	II-B-6	Additional Items Claimed in Rate Base
Exhibit RAD-16	II-C-1	Statement of Income
Exhibit RAD-17	II-C-2	Similar Schedule Historic Test Year
Exhibit RAD-18	II-D-1	Schedule of Revenues and Expenses
Exhibit RAD-19	II-D-2	Summary of Test Year Adjustments
Exhibit RAD-20	II-D-3	Nonrecurring & Extraordinary Items
Exhibit RAD-21	II-D-4	Extraordinary Property Losses
Exhibit RAD-22	II-D-5	Reserve for Uncollectible Accounts
Exhibit RAD-23	II-D-6	Claim for Rate Case Expense
Exhibit RAD-24	II-D-7	Schedule of Expenses for Test Years
Exhibit RAD-25	II-D-8	Charges by Affiliates and Service Agreement
Exhibit RAD-26	II-D-9	Schedule of Social and Service Organization Memberships
Exhibit RAD-27	II-D-10	Payroll and Employee Benefits
Exhibit RAD-28	II-D-11	Leasing Costs and Method for Calculating Payments
Exhibit RAD-29	II-D-12	Past and Anticipated Accounting Changes, Audit Reports
Exhibit RAD-30	II-D-13	Gross Salvage, Cost of Removal, Third Party Reimbursements and Net Salvage

Exhibit	FR	Description
Exhibit RAD-31	II-D-14	Debt Interest Utilized for Test Year Income Tax Calculations
Exhibit RAD-32	II-D-15	Schedule of Taxes Other Than Income Taxes
Exhibit RAD-33	II-D-16	Adjustments from Taxable Net Income
Exhibit RAD-34	II-D-17	Prior Year Claims for Income Tax Refunds
Exhibit RAD-35	II-D-18	Accumulated Deferred Taxes
Exhibit RAD-36	II-D-19	Federal Corporate Graduated Tax Rates
Exhibit RAD-37	II-D-20	Costs of Removal
Exhibit RAD-38	II-D-21	Income Tax Loss/Gain Carryovers from Previous Years
Exhibit RAD-39	II-D-22	Elimination of Tax Savings by Payment of Actual Interest on Construction Work In Progress
Exhibit RAD-40 **(Highly Confidential)**[2]	II-D-23	Tax Liability Allocated as Computed on the Basis of Separate Returns of Members
Exhibit RAD-41	II-D-24	Deferred Income Taxes Resulting from Use of Accelerated Tax Depreciation
Exhibit RAD-42	II-D-25	Accumulated and Unamortized Investment Tax Credit Schedule
Exhibit RAD-43	II-D-26	Additional Claims Not Otherwise Explained in Statement of Operating Income

[2] Exhibit RAD-40 contains a **Highly Confidential** attachment that is being provided to the Commission in hard copy only.

Exhibit	FR	Description
Exhibit RAD-44	II-D-27	Rate Base and Operating Income Adjustments for Jurisdictional Test Year Claim
Exhibit RAD-45	II-E-1	Budget Guidelines and Budget Process
Exhibit RAD-46	V-A-1 V-A-2 V-B-1 V-B-3	Original Cost of Plant, Reserves and Accruals by Functions for Fully Projected Future Test Year Ending 12/31/2017
Exhibit RAD-47	V-A-1 V-A-2 V-B-1 V-B-3	Original Cost of Plant, Reserves and Accruals by Functions for Future Test Year Ending 12/31/2016
Exhibit RAD-48	V-A-1 V-A-2 V-B-1 V-B-3	Original Cost of Plant, Reserves and Accruals by Functions for Historic Test Year Ended 12/31/2015
Exhibit RAD-49	V-A-3	Schedules Showing Methodology Used to Update Original Cost Plant and Reserves
Exhibit RAD-50	V-A-4	Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes (Fully Projected Future Test Year)
Exhibit RAD-51	V-A-4	Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes (Future Test Year)
Exhibit RAD-52	V-A-4	Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes (Historic Test Year)
Exhibit RAD-53	V-B-2 V-C V-D-3 V-E	Annual Depreciation Review on Capital Plant Investments

Exhibit	FR	Description
Exhibit RAD-54	VI-A	Balance Sheet
Exhibit RAD-55	VI-B	Comparative Income Statements
Exhibit RAD-56	VI-C	Plant in Service
Exhibit RAD-57	VI-D	Reserve for Depreciation
Exhibit RAD-58	I-A-4	Generating Plant Addition or Removal from Service
Exhibit RAD-59	I-B-2	Description of Property of Utility and Explanation of System Operation
Exhibit RAD-60	III-B-5	Long-Term Debt Reacquisition
Exhibit RAD-61	66 Pa.C.S. § 1316	Summary of Advertising Expenses
Exhibit RAD-62	52 Pa. Code § 69.36	Company Actions to Encourage Development of Cost-Effective Energy Supply Alternatives
Exhibit RAD-63		Distribution Storm Costs
Exhibit RAD-64		Updated Legacy Meters and Associated COR
Exhibit RAD-65		Bonus Depreciation Tax
Exhibit RAD-66		Comparative Income Statement
Exhibit RAD-67		Comparison of Plant Additions

Statement No. 3 – Direct Testimony of Kevin M. Siedt

Exhibit	FR	Description
Exhibit KMS-1		Normalized Sales and Revenues for the Test Years ending December 31, 2017, December 31, 2016, and December 31, 2015
Exhibit KMS-2		Summary of Present and Proposed Distribution Revenues
Exhibit KMS-3		Customer Charge Analyses
Exhibit KMS-4		Proof of Revenue Analyses
Exhibit KMS-5		Customer Impact Analyses
Exhibit KMS-6		Cost And Proposed Base Rate Revenue Curves
Exhibit KMS-7		Matrix of Tariff Charges
Exhibit KMS-8	52 Pa. Code §53.52(a)-(d) IV-A-1 IV-A-2 IV-A-3 IV-A-4 IV-A-5 IV-B-1 IV-B-2 IV-B-3 IV-C IV-D-1 IV-D-2 IV-E-2	Responses to Various Filing Requirements

Volume II

Statement No. 4 – Direct Testimony of Thomas J. Dolezal

Exhibit	FR	Description
Exhibit TJD-1		Cost of Service Studies (COSS) Using Non-Coincident Peak Demands
Exhibit TJD-2		Supporting Studies For Functionalizing Costs & Developing Allocation Factors Used in COSS

Statement No. 5 – Direct Testimony of Jeffrey L. Adams

Exhibit	FR	**Description**
Exhibit JLA-1		Cash Working Capital

Statement No. 6 – Direct Testimony of Laura W. Gifford

Exhibit	FR	Description
Exhibit LWG-1		Default Service Support Rider / Hourly Pricing Rider Uncollectible Accounts Expense
Exhibit LWG-2		Unbundled Uncollectible Accounts Expense
Exhibit LWG-3		Cost Baseline for Smart Meter Savings

Statement No. 7 – Direct Testimony of John J. Spanos

Exhibit	FR	Description
Exhibit JJS-1		2015 Depreciation Study
Exhibit JJS-2		2016 Depreciation Study
Exhibit JJS-3		2017 Depreciation Study

Exhibit	FR	Description
Exhibit JJS-4		Electric Plant in Service Used in Studies
Exhibit JJS-5		Comparison of Depreciation Used in Studies
Exhibit JJS-6	V-A-3	Schedules Showing Methodology Used to Update Original Cost Plant and Reserves
Exhibit JJS-7	V-B-1	Original Cost of Plant, Reserves and Accruals by Functions
Exhibit JJS-8	V-B-2	Annual Depreciation Review on Capital Plant Investments
Exhibit JJS-9	V-C-1	Annual Depreciation Review on Capital Plant Investments
Exhibit JJS-10	V-D-1	Original Cost of Plant, Reserves and Accruals by Functions
Exhibit JJS-11	V-D-2	Annual Depreciation Review on Capital Plant Investments
Exhibit JJS-12	V-E-1	Annual Depreciation Review on Capital Plant Investments
Exhibit JJS-13	VI-C	Plant in Service
Exhibit JJS-14	VI-D	Reserve for Depreciation

Volume III

Statement No. 8 – Direct Testimony of Pauline M. Ahern

Exhibit	FR	Description
Exhibit PMA-1		Fair Rate of Return

Statement No. 9 – Direct Testimony of Joseph Dipre

Exhibit	FR	Description
Exhibit JD-1	II-B-5	Compensating Bank Balances
Exhibit JD-2	II-E-2	Projected Operating and Capital Budgets
Exhibit JD-3	III-A-1	Claimed Capitalization
Exhibit JD-4	III-A-2	Capitalization and Capitalization Ratios
Exhibit JD-5	III-B-1	Schedule of Long Term Debt
Exhibit JD-6	III-B-2	Statement Regarding Claim for Economic Cost of Debt
Exhibit JD-7	III-B-3	Bank Notes Payable for Test Year and Latest Annual Historical Period
Exhibit JD-8	III-B-4	Other Short-Term Debt Outstanding
Exhibit JD-9	III-C	Embedded Cost of Preferred Stock Equity
Exhibit JD-10	III-D-2	Common Stock Dividend Record
Exhibit JD-11	III-D-3	Issuances of Common Stock
Exhibit JD-12	III-D-4	Utility and Parent Stock Offerings
Exhibit JD-13	III-E-1	Consolidated Capital Structure and Cost Claims
Exhibit JD-14	III-E-2	FirstEnergy Corp (Stand Alone/Parent) Capitalization & Capitalization Ratios
Exhibit JD-15	III-E-3	Balance Sheet and Income Statement

Exhibit	FR	Description
Exhibit JD-16	III-E-4	Corporate Summary Report and Organizational Structure
Exhibit JD-17	III-F-1	Quarterly and Annual Reports
Exhibit JD-18	III-F-2	Projected Capital Requirements and Sources
Exhibit JD-19	III-F-3	Required Coverage Requirements or Capital Structure Ratios
Exhibit JD-20	III-F-4	Comparative Financial Data
Exhibit JD-21	III-D-1	Claimed Common Equity Rate of Return
Exhibit JD-22		Capitalization & Capitalization Ratios
Exhibit JD-23		Schedule of Long Term Debt Outstanding at 12/31/2017
Exhibit JD-24		Capital Cost Rates 12/31/2017

Statement No. 8

Met-Ed Statement No. 8

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2016-2537349

Direct Testimony
of
Pauline M. Ahern, CRRA

List of Topics Addressed

Fair Rate of Return

TABLE OF CONTENTS

DIRECT TESTIMONY
OF
PAULINE M. AHERN, CRRA

I. INTRODUCTION AND PURPOSE

Q. Please state your name, occupation and business address.

A. My name is Pauline M. Ahern. I am a Partner with Sussex Economic Advisors, LLC. My business address is 1900 West Park Road, Suite 250, Westborough, MA 01581. My mailing address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

Q. Please summarize your professional experience and educational background.

A. I have offered expert testimony on behalf of investor-owned utilities before thirty state regulatory commissions in the United States as well as one provincial regulatory commission in Canada on rate of return issues, including but not limited to common equity cost rate, fair rate of return, capital structure, relative investment risk and credit quality. I am a graduate of Clark University where I was awarded a Bachelor of Arts degree with honors in Economics. I was also awarded a Master of Business Administration with high honors and a concentration in finance by Rutgers University.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured monthly. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

In addition, I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA") and currently serve on its Board of Directors, having previously served two terms as SURFA's President from 2006 – 2008 and 2008 – 2010 and as its Secretary/Treasurer from 2004 – 2006. In 1992, I was awarded the professional designation "Certified Rate of Return Analyst" ("CRRA") by SURFA, which is based upon education, experience and the successful completion of a comprehensive written examination.

Lastly, I am an associate member of the National Association of Water Companies, serving on its Finance/Accounting/Taxation and Rates and Regulation Committees; a member of the Advisory Council of the Financial Research Institute – University of Missouri – Robert J. Trulaske, Sr. College of Business; a member of the American Finance and Financial Management Associations; and, a member of AGA's State Affairs Committee.

The details of my educational background, expert witness appearances, presentations I have given and articles I have co-authored are set forth in Appendix A to this testimony.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed" or the "Company").

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to support the cost rate which Met-Ed should be afforded the opportunity to earn on the common equity portion of its jurisdictional rate base.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. It has been marked for identification as Met-Ed Exhibit PMA-1 and consists of Schedules 1 through 10.

Q. Please describe Metropolitan Edison Company.

A. Met-Ed provides electric service to approximately 561,400 customers in central and eastern Pennsylvania. As a wholly-owned subsidiary of FirstEnergy Corp. ("FE" or the "Parent"), the Company's common stock is not publicly traded. Met-Ed had a summer peak load in 2015 of about 2,791 MW, with about two-thirds of that load attributable to residential and small commercial customers. In addition to owning, operating and maintaining 11,292 circuit miles of distribution lines, Met-Ed currently owns 1,406 miles of transmission lines and related facilities within its service territory, which are under the operational control of the PJM Interconnection, LLC ("PJM") as the regional transmission organization ("RTO").

Q. Have you reviewed financial information for Met-Ed?

A. Yes. As shown on Schedule 1, during the five-year period ending 2014, the achieved average earnings rate on book common equity for Met-Ed was 4.10%. The five-year ending 2014 average common equity ratio based upon total permanent capital was 52.64%, while the five-year average dividend payout ratio was 17.71%.

Total debt as a percent of EBITDA[1] for the years 2010-2014 ranged between 3.46 and 13.46 times, averaging 5.94 times, while funds from operations as a percent of total debt ranged from a negative 2.70% to a positive 8.87%, averaging 4.58%.

Q. How did you determine Met-Ed's cost of common equity?

A. As a wholly-owned subsidiary of FE, Met-Ed's common stock is not publicly traded. Hence, a market-based common equity cost rate cannot be determined directly for the Company. Consequently, I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk, i.e., a proxy group, for insight into a recommended common equity cost rate applicable to Met-Ed (the "Electric Proxy Group"). Using companies of relatively similar risk as proxies is consistent with the principles of fair rate of return established in the Hope[2] and Bluefield[3] cases, adding reliability to the informed expert judgment necessary to arrive at a recommended common equity cost rate. However, no proxy group is identical in risk to any single entity, such as the Company. Accordingly, an assessment of relative risk between the Company and the Electric Proxy Group must be made to determine whether any adjustments to the Electric Proxy Group's indicated common equity cost rate are necessary.

In determining the Electric Proxy Group's cost of equity, I applied several well-recognized models, i.e., the Discounted Cash Flow Model ("DCF"), the Risk Premium Model ("RPM") and the Capital Asset Pricing Model ("CAPM"). In addition, I applied

---

1 Earnings Before Interest, Taxes, Depreciation and Amortization.
2 *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).
3 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

the DCF, RPM and CAPM to the market data of a Non-Price Regulated Proxy Group comparable in total risk to the Electric Proxy Group.

As summarized on Schedule 2 and in Table 1 below, I conclude that a common equity cost rate of 10.42%, inclusive of flotation costs, is reasonable and appropriate. Once adjustments are made to the 10.42% cost of common equity to reflect Met-Ed's greater business risk (0.10%) and greater credit risk (0.40%) relative to the Electric Proxy Group, a risk-adjusted cost of common equity of 10.92% results, which, when rounded to 10.90%, is my recommended common equity cost rate applicable to Met-Ed in this proceeding.

Table 1

Discounted Cash Flow Model	8.80%[4]
Range: 6.33% - 12.31% (midpoint: 9.32%)	
Risk Premium Model	10.51%
Range: 10.25% - 10.77% (midpoint: 10.51%)	
Capital Asset Pricing Model	9.89%
Range: 8.53% - 10.83% (midpoint: 9.68%)	
Cost of Common Equity Models Applied to the Non-Price Regulated Proxy Group	11.13%
Range: 10.86% - 11.29% (midpoint: 11.07%)	
Indicated Common Equity Cost Rate Before Adjustment	10.15%[5]
Flotation Costs	0.27%
Indicated Common Equity Cost Rate for the Electric Proxy Group before Company Specific Risk Adjustments	10.42%
Business Risk Adjustment	0.10%
Credit Risk Adjustment	0.40%
Indicated Common Equity Cost Rate After Adjustment	10.92%
Recommended Common Equity Cost Rate	10.90%

4 As discussed later in my testimony, application of the DCF model to current market data understates the required return on common equity by as much as 360 basis points due to a highly unusual and, in all likelihood, temporary convergence of historically anomalous market conditions. Accordingly, the results of that model should be given only very limited weight in deriving a reasonable return on equity in this proceeding.

5 The average of the mean and median of the results of the DCF, CAPM and RPM methods applied to the market data of the Electric Proxy Group and a Non-Price Regulated Proxy Group, 10.14%, has been rounded to 10.15%. By doing so, I have not only considered the results of each cost of common equity model, but have mitigated the effect of outliers on either the high or the low side.

II. CAPITAL MARKET CONDITIONS

Q. Please describe current capital market conditions.

A. Because the models used to estimate the cost of common equity are meant to reflect current and expected capital market conditions, it is important to assess the reasonableness of the results of any model in the context of observable market data. To the extent model assumptions or results are incompatible with such data, judgment must be applied in both the application of methods, and in the interpretation of their results.

Q. Please discuss how the Federal Reserve Bank's market intervention affects the estimation of the cost of capital.

A. Much has been reported about the Federal Reserve Bank's ("Fed") market intervention since 2007, and the effect of that intervention on interest rates. Aside from that effect, an important consideration is the extent to which those actions have obscured the long-standing relationships among financial metrics sometimes used in assessing the cost of common equity.

Beginning in 2008, the Fed proceeded on a steady path designed to lower long-term government bond yields. Fed policy actions were intended to put downward pressure on longer-term interest rates by having the Fed take onto its balance sheet some of the duration and prepayment risks that would otherwise have been borne by private investors. Under that policy, "Securities Held Outright" on the Fed's balance sheet increased from approximately $491 billion at the beginning of October 2008 to approximately $4.25 trillion by the end of January 2016. In context, the securities held by the Fed represented approximately 3.31% of GDP at the end of September 2008, and rose to approximately

23.43% of GDP at the end of January 2016.[6] As such, Fed policy actions have been a significant source of liquidity, and have had a substantial effect on capital markets.

As a result of the Fed's accommodative monetary policies, the U.S. stock market has recovered with the S&P 500 rising approximately 185.0% from its low in early March 2009. That stock price appreciation occurred despite the market's recent extreme volatility in response to the turmoil in the global economy, falling oil prices, and the uncertainty and direction of the Fed's interest rate decisions.

Q. Is the market expecting increases in interest rates?

A. Yes. The U.S. thirty-year Treasury bond is currently forecasted to yield an average of 3.35%[7] over the six quarters ended with the second quarter 2017, 4.5% for 2017-2021 and 4.8% for 2022-2026[8] by *Blue Chip Financial Forecasts* ("*Blue Chip*"). In addition, the iShares 20+ Year Treasury Bond ETF ("TLT") Option Chain, an exchange-traded fund of long-term U.S. Government bonds, provides insight into the market's expectations of future interest rate trends. Because the price of bonds is inversely related to interest rates, the TLT has increased in value as interest rates have fallen over time (see Chart 1, below).

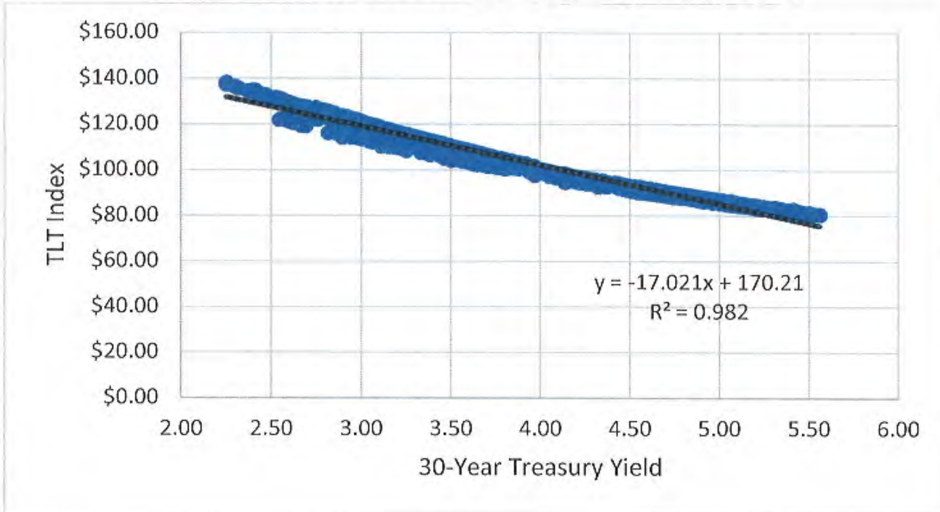
---

6 www.federalreserve.gov / www.bea.gov/national/

7 From *Blue Chip Financial Forecasts*, February 1, 2016. Schedule 5, p. 9.

8 From *Blue Chip Financial Forecasts*, December 1, 2015. Schedule 5, p. 10.

Chart 1: TLT Index vs. 30-Year Treasury Yield[9]



The TLT provides a market-based understanding of whether investors expect interest rates will increase or decrease by reviewing the premium they are willing to pay for the option to buy or sell the TLT, at the current market price, in the future. If investors are willing to pay more for the option to sell the TLT in the future (at today's price) than they are willing to pay for the option to buy the TLT (also at today's price), that suggests that, on balance, the market perceives a greater prospect of interest rate increases than decreases. Based upon data from NASDAQ, as of January 2016, the option to sell the TLT in January 2018 (the furthest priced option) at the current price is more than twice the value of the option to buy the TLT. Because bond prices fall as interest rates increase, this means that investors perceive a greater likelihood of increases in long-term interest rates than decreases.

Q. What is the market's current assessment of expected volatility?

A. One measure of the expected volatility, or risk, of the U.S. stock market is the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX"), which measures market

9 Source: Yahoo!Finance

expectations of near-term volatility in the U.S. stock market implied by near and next-term options on the VIX index. The VIX, sometimes referred to as the "fear index", is a highly visible and often-reported barometer of investor risk sentiments.

Although the VIX is not presented as a percentage, it should be understood as such. Thus, if the VIX stood at 17.00, it would be interpreted as an expected standard deviation in annual returns on the market index of 17.00% over the coming thirty trading days. As Chart 2 reflects, since its inception in 1990, the VIX has averaged approximately 19.83, relatively close to the long-term average annual standard deviation in returns on the S&P 500 of 20.55%.

Chart 2: VIX Daily Levels and Long-Term Average[10]

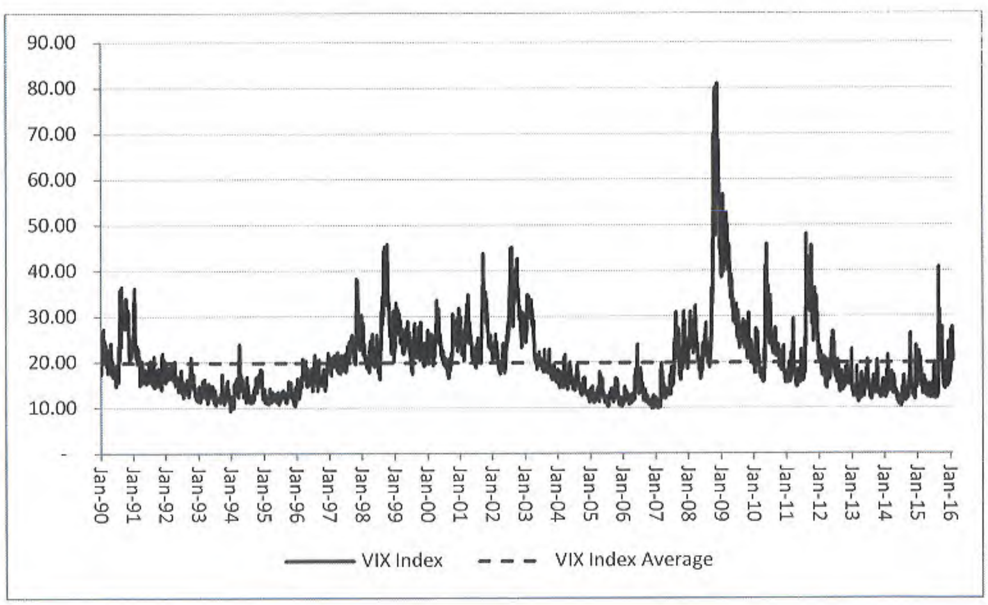


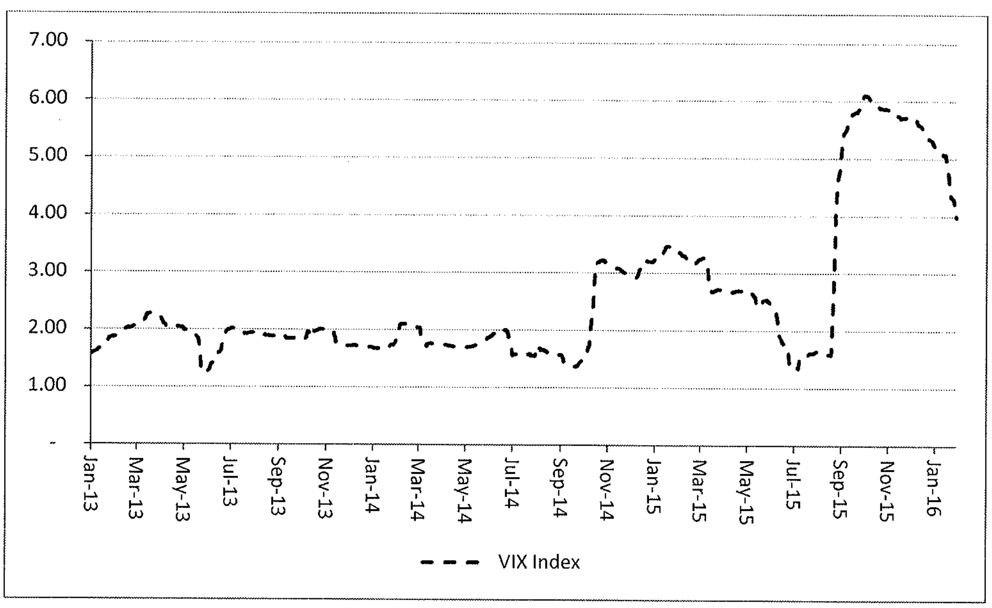
Chart 2 highlights several relevant points. First, the VIX has been at relatively low levels in recent years. However, significant volatility returned to the U.S. stock market

[10] Source: Bloomberg Financial.

beginning in the latter portion of 2015. From that broad perspective, equity risk is currently elevated relative to recent historical levels.

A further measure of market uncertainty is the volatility of the VIX itself, or the volatility of volatility, as measured by the standard deviation of the VIX. As Chart 3 (below) notes, both moved in a relatively narrow range during 2013, but since then have increased quite noticeably. Such volatility indicates that, although interest rates are still near historical lows in the U.S. market, there remains significant, if not greater, risk to common equity investment in today's markets, with investors requiring greater returns to bear that risk, consistent with the basic financial principle of risk and return.

Chart 3: Standard Deviation (100 days) of VIX[11]



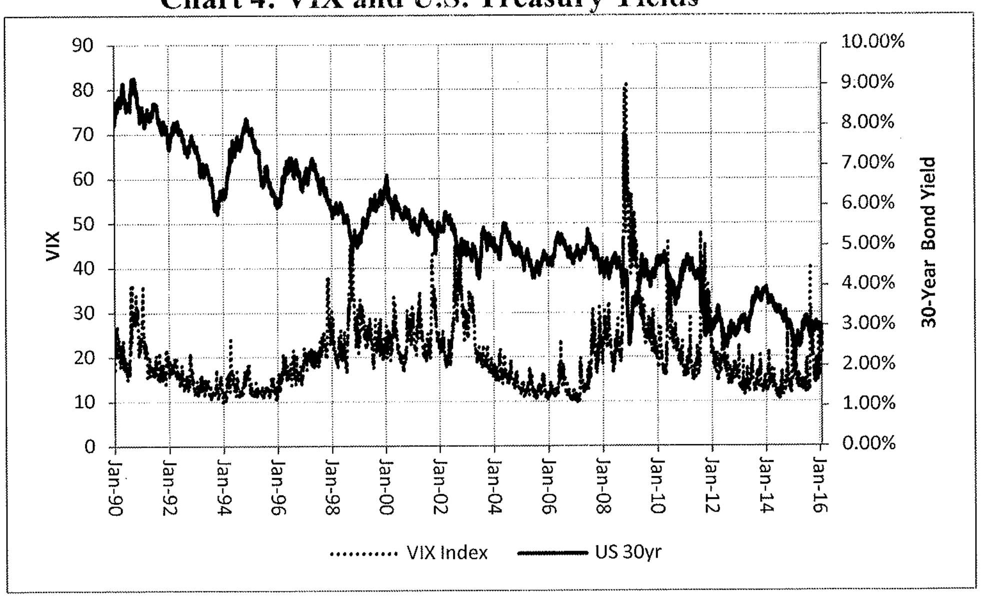
Just as market intervention by the Fed has reduced interest rates, it has also reduced volatility. For example, each time the Fed began to purchase bonds (as evidenced by the increase in "Securities Held Outright" on its balance sheet), volatility subsequently declined. In fact, in September 2012, when the Fed began to purchase long-term

[11] Source: Bloomberg Financial.

securities at a pace of $85 billion per month, volatility (as measured by the VIX) fell, and through October 2014 remained in a relatively narrow range. The reason is quite straight-forward: investors became confident that the Fed would intervene if markets were to become unstable.

Even with the effect of Fed intervention, periods of increased equity market volatility have been associated with unusually low government bond yields. That relationship makes sense, given that investors increasingly focus on capital preservation during turbulent markets. As Chart 4, below, demonstrates, when volatility peaks (as measured by the VIX), government bond yields fall given that increased demand for safe-haven securities will bid up their price, and down their yield.

Chart 4: VIX and U.S. Treasury Yields[12]



The important analytical issue is whether we can infer that risk aversion among equity investors is at a historically low level, or lower than it had been in recent years, implying a correspondingly low cost of common equity. Given the negative relationship between

12 Source: Bloomberg Financial.

the expansion of the Fed's balance sheets and equity market volatility (as measured by the VIX), and in light of the fact that current volatility is considerably greater than prior levels, it is difficult to conclude that fundamental investor risk aversion and investor return requirements are lower than they have been in recent years. In other words, because investors require higher returns for bearing greater risk, given that current market volatility, i.e., risk, is higher than in recent years, investors' required returns must be higher as well.

The low interest rate environment associated with the Fed's intervention may lead some analysts to conclude that current capital costs, including the cost of common equity, are low and will continue to be so. That conclusion, however, only holds true under the hypothesis of Perfectly Competitive Capital Markets ("PCCM") and the classical valuation framework which, under normal economic and capital market conditions, underpin the traditional cost of common equity models. PCCM are capital markets in which no single trader, or "market-mover," would have the power to change the prices of goods or services, including bond and common stock securities. In other words, under the PCCM hypothesis, no single trader would have a significant effect on market prices.

Classic valuation theory assumes that investors trade securities rationally with prices reflecting their perceptions of value. Although the Fed has always had the ability to set the benchmark interest rates, is has been maintaining below normal rates to stimulate continued economic and capital market recovery. It therefore is reasonable to conclude that the Fed and other central banks are acting as market-movers, which has a significant effect on the market prices of both bonds and stocks in all markets where a central bank is maintaining historically low interest rates. The presence of market-movers such as the Fed in current capital markets runs counter to the PCCM, which is the foundation of traditional cost of common equity models.

The engineering of interest rates directly affects the measurement of the cost of common equity. In my opinion, therefore, the results of traditional cost of common equity models should be viewed with even greater scrutiny under current economic and capital market conditions. The current and expected interest rate environment, coupled with the Fed's engineering of interest rates, suggests that the traditional cost of common equity models'[13] tendency to understate the investor required cost of common equity will be exacerbated. Consequently, the results of these models, including those presented in this testimony, are currently and prospectively particularly conservative estimates, i.e., on the low side, of the investor required rate of return on common equity.

III. GENERAL PRINCIPLES AND INVESTMENT RISK

Q. What general principles have you considered in arriving at an indicated common equity cost rate of 10.42%, inclusive of flotation costs but exclusive of company-specific adjustment for size and credit quality differences, for the Electric Proxy Group?

A. The cost of common equity is defined as that return which investors require to make an equity investment in a given firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of

[13] DCF, RPM and CAPM.

the "cost of debt" and the "cost of equity"; together, they are referred to as the "cost of capital."

The cost of capital (including the costs of both debt and equity) is based upon the economic principle of "opportunity cost," meaning that investing in any asset/security implies a forgone opportunity to invest in alternative assets/securities. For any investment to make sense to the investor, its expected return must be at least equal to the return expected on alternative investment opportunities of comparable risk. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the cost of debt is contractually defined and can be directly observed in the market as the interest rate or yield on debt securities. The cost of equity, on the other hand, is neither directly observable in the market nor has a contractual obligation. Rather, because common equity investors have a claim on a firm's cash flows only after debt holders are paid, the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Because common equity investors bear this "residual risk," they require higher returns than debt holders. In that basic sense, common equity and debt investors are distinct: they invest in different securities; face different risks; and require different returns.

The cost of capital, specifically the cost of common equity or the investor required return, is also an economic and financial concept which refers to the *ex-ante,*[14] or the expected

[14] Before the fact.

return on an investment at the market value of the publicly traded common shares of a corporation. According to the basic financial principle of risk and return, the investor required return on investment is a function of the level of investor perceived risk as reflected in the market prices paid. The higher/lower the investor perceived risk, the higher/lower the investor required return. The investor required return is also forward-looking, or expectational, as it is the return which the investor expects to receive in the future for investing capital today.

In unregulated industries, the competition of the marketplace is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. A sufficient level of earnings is required to assure that the utility can: 1) fulfill its obligations to the public while providing safe and reliable service at all times; 2) maintain the integrity of presently invested capital; and 3) attract needed new capital at a reasonable cost in competition with other firms of comparable risk. This is consistent with the previously noted fair rate of return standards established by the U.S. Supreme Court in the *Hope* and *Bluefield* cases.

In rate base/rate of return regulation, the authorized (allowed) return on common equity is defined as the investor required return. In turn, the investor required return is defined as the return required by the investor on the funds invested in the publicly traded common stocks of companies. As stated previously, the cost of common equity is not directly observable in the capital markets since there is no contractual basis or obligation on the part of a firm to provide a return to its common shareholders, unlike the contractual coupon, or interest, rate on its debt obligations. Therefore, the cost of common equity must be estimated from market (economic and financial) data, using financial models developed for that purpose, such as the CAPM, DCF and RPM. Consequently, marketplace data must be relied upon in determining a common equity cost rate appropriate for ratemaking purposes.

In short, my recommended common equity cost rate is derived from marketplace data of a proxy group of utilities as similar in risk as possible to the Company, based upon selection criteria that will be discussed subsequently. The use of the market data of a proxy group of similar risk companies and the use of multiple cost of common equity cost rate models add reliability to the informed expert judgment used in arriving at a recommended common equity cost rate.

Q. Why have you used multiple cost of common equity models to estimate the company's cost of common equity?

A. Each of the financial models used to estimate the cost of common equity is subject to certain assumptions, which may be more or less applicable under differing market conditions. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the models' results all require the application of reasoned judgment. In the final analysis, the recommended cost of common equity should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments relative to market conditions at the time the analysis is conducted.

Quantitative financial models produce a range of results from which the market, or investor, required return must be estimated. That estimation must be based upon a comprehensive review of relevant data and information, including capital market conditions, and does not necessarily lend itself to a strict mathematical estimation. The key consideration in arriving at a recommended common equity cost rate is to ensure that the overall analysis reasonably reflects investors' expectations in light of capital markets in general, and the investment risk of the subject company (in the context of the proxy companies) in particular.

Because empirical financial models for determining the cost of common equity are subject to limiting assumptions or other constraints, most finance texts recommend using multiple approaches to estimate the cost of common equity. As a practical matter, no individual model is more reliable than all others under all market conditions. Therefore, it is both prudent and appropriate to use multiple methodologies in order to mitigate the effects of limiting assumptions and inputs associated with any single approach. As such, I have considered the results of multiple common equity cost rate models in arriving at my recommended common equity cost rate for the Company.

That the use of multiple common equity cost rate models adds reliability to the estimation of the investor required return is well supported in the academic literature.

Morin states:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate a theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.

> **No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment.** Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. (emphasis added)
>
> * * *
>
> The financial literature supports the use of multiple methods. Professor Eugene Brigham, a widely respected scholar and finance academician, asserts[1(footnote omitted)]
>
>> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.
>
> Another prominent finance scholar, Professor Stewart Myers, in an early pioneering article on regulatory finance, stated[(footnote omitted)]:
>
>> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data. (emphasis added)
>
> Reliance on multiple tests recognizes that no single methodology produces a precise definitive estimate of the cost of equity. As stated in Bonbright, Danielsen, and Kamerschen (1988), '*no single or group test or technique is conclusive*.' Only a fool discards relevant evidence. (italics in original) (emphasis added)
>
> * * *
>
> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory

formalized in the CAPM and other risk premium methods. **The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity.** It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies. (emphasis added) [15]

Q. Has the Pennsylvania Public Utility Commission ("Commission") also relied upon multiple models when determining an allowed return on common equity for a utility company?

A. Yes. In its Opinion and Order entered January 23, 2014, the Commission, too, supported the use of multiple models in establishing an allowed return on equity ("ROE") when it stated:

> The ALJ concluded that I&E provided the most reasonable resolution of this issue. The ALJ stated that the OCA's proposed rate of return is a bit too parsimonious, whereas Columbia's requested rate of return is excessive and based on an overly generous methodology. Accordingly, the ALJ adopted I&E's recommended ROE of 9.15%, which would produce an overall rate of return of 7.07% using the 50/50 capital structure recommended by I&E. R.D. at 43-46.
>
> * * *
>
> Upon consideration of the evidence in this proceeding, we will modify the ALJ's recommendation and adopt a rate of return on common equity of 9.75%.
>
> * * *
>
> In this case, the range of ROE recommendations presented by the Parties based on the DCF methodology is 8.25% to 11.35%. Based on our review of the testimony, data, and **cost models presented**, we believe that the evidence in this case supports an ROE finding in the reasonable range of 9.25% to 10.25% using the DCF method as the foundation.[16]

---

[15] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006) 396-398, 428-431.

[16] *Pennsylvania Public Utility Commission v. Columbia Water Company*, Docket No. R-2013-2360798 (Order entered January 23, 2014), pp. 39, 43 (emphasis added).

Likewise, the following year, in its Opinion and Order entered January 28, 2015, the Commission once again supported the use of multiple models in establishing an allowed ROE when it stated:

> Upon consideration of the evidence in this proceeding, we will modify the ALJ's recommendation and adopt a rate of return on common equity of 10.0%.
>
> * * *
>
> As discussed, *supra*, the OCA recommends a return of 9.20% as the midpoint of its DCF and CE analyses; I&E recommends a return of 8.89% based on its DCF analyses; and the Company proposes a return of 10.3%, which utilizes its DCF, RP, and CAPM analyses to which the Company adds a size risk adjustment of 75 basis points. Based on our review of the testimony, data, and cost models presented, and considering our adoption of a 60% / 40% hypothetical capital structure, we believe the range of returns provided in evidence supports an ROE finding of 10.0% for our ratemaking determinations herein.[17]

In view of the foregoing, I rely upon the results of three well-tested market models: the DCF, RPM and CAPM in arriving at a common equity cost rate applicable to the Company.

Q. Please define business risk and explain why it is important to the determination of a fair rate of return.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk often is discussed in the context of business risk and financial risk.

---

[17] *Pennsylvania Public Utility Commission v. Emporium Water Company*, Docket No. R-2014-2402324, (Order entered January 28, 2015), pp. 34-35.

Business risk reflects the uncertainty associated with owning a company's common stock, without consideration of the company's use of debt and/or preferred financing. One way of understanding the distinction between business and financial risk is to view the former as the uncertainty in the expected earned return on common equity assuming the firm is financed with no debt.

Examples of the business risk generally faced by utilities include, but are not limited to, the regulatory environment, customer mix and concentration of customers, service territory economic growth, market demand, supply, operations, capital intensity, size, and the degree of operating leverage, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks according to individual categories, as a practical matter they are inter-related and are not wholly distinct from another. Therefore, it is difficult, if not impossible, to specifically and numerically quantify the effect on investors' required return, i.e., the cost of capital. For the purpose of determining the proper ROE, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to additional risk, the required return will increase; the converse also is true.

For regulated utilities, business risks are both long and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability for investors to recover the return on and of their capital. Moreover, unlike unregulated entities, utilities accept the obligation to serve: providing safe and reliable service at all times and, as such, generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress.

Because utilities invest in long-lived, essentially permanent assets, long-term business risks are of considerable concern to equity investors. That is, the risk of not recovering the return on and of their investment extends far into the future. But, the timing and nature of events that may lead to losses also are uncertain and, as a consequence, those risks and their implications for the required ROE tend to be difficult to quantify. That does not mean, however, that the risk is of no consequence to investors. For example, analysts may apply simulation-based methods to assess the potential risk. However, in the final analysis, like the investors that commit their capital, regulatory commissions must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required ROE.

It is important to also bear in mind the distinction between debt and equity investors when assessing the implications of business risks on the cost of equity. In general, whereas debt holders have a priority claim on earnings and assets, equity holders are the "residual claimants." Because they bear that residual risk, equity investors require a premium over the return required by debt investors. That is, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk (leading to the equity risk premium).

Q. Please define financial risk and explain why it is important to the determination of a fair rate of return.

A. Financial risk is the additional risk that a company may not have sufficient cash flows to meet its financial obligations and is created by the introduction of senior capital, i.e., debt and/or preferred stock, into the capital structure. The higher the proportion of senior capital in the capital structure, the higher the financial risk which must be factored into the common equity cost rate, consistent with the previously mentioned basic financial principle of risk and return, i.e., investors demand a higher common equity return as compensation for bearing higher investment risk.

Q. Can the investment risk of an enterprise be proxied by bond and credit ratings?

A. Yes, similar bond/issuer credit (bond/credit) ratings reflect and are representative of similar combined business and financial risks, i.e., total risk faced by bond investors.[18] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are similar, albeit not necessarily equal, as the purpose of the bond/credit rating process is to assess overall credit quality or credit risk and not just common equity risk.

However, it must be kept in mind that a long-term issuer credit or bond issue rating is an opinion regarding the particular company's overall financial capacity to pay its financial obligations as they come due and payable. The claims of equity holders, on the other hand, are subordinate to the claims of debt holders, and are perpetual in life. As noted

18 Risk distinctions within Standard & Poor's ("S&P") bond rating categories are recognized by a plus or minus, i.e., within the A category, an S&P rating can be at A+, A, or A-. Risk distinctions for Moody's ratings are distinguished by numerical rating gradations, i.e., within the A category, a Moody's rating can be A1, A2 and A3.

above, whereas bondholders can be assured of the probability that a particular company will be able to meet its financial obligations (and thus have higher credit/bond ratings), common equity holders bear the residual risk of insufficient or volatile cash flows in perpetuity. For that fundamental reason, the risks of owning common equity do not directly correspond to the risks of owning bonds. The two have similar considerations, but only to a point.

IV. COMMON EQUITY COST RATE FINDINGS FOR THE ELECTRIC PROXY GROUP

Q. Please explain how you chose the Electric Proxy Group.

A. I chose the Electric Proxy Group by selecting those companies which met the following criteria:

1) They are included in the Electric Utility Group[19] of *Value Line Investment Survey's* Standard Edition;
2) They had 70% or greater of their 2014 total operating income derived from, and 70% or greater of their 2014 total assets were devoted to, regulated electric operations;
3) They had not publicly announced involvement in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) at the time of the preparation of this testimony;
4) They have not cut or omitted their common dividends during the past five years or through the time of the preparation of this testimony;

[19] *Value Line*'s Electric Utility Group consists of Electric Utility (East), Electric Utility (Central) and Electric Utility (West).

5) They have *Value Line* and Bloomberg adjusted betas;

6) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and,

7) They have *Value Line*, Reuters, Zacks or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following eighteen companies met these criteria:

- ALLETE, Inc. (ALE);
- Alliant Energy Corp. (LNT);
- Ameren Corp. (AEE);
- American Electric Power Co., Inc. (AEP);
- Consolidated Edison, Inc. (ED);
- Edison International (EIX);
- El Paso Electric Co. (EE);
- Great Plains Energy, Inc. (GXP);
- IDACORP. Inc. (IDA);
- OGE Energy Corp. (OGE);
- Otter Tail Corp. (OTTR);
- PG&E Corp., (PCG);
- Pinnacle West Capital Corp. (PNW):
- PNM Resources, Inc. (PNM);
- Portland General Electric Co. (POR)
- SCANA Corp. (SCG);
- Westar Energy, Inc. (WR); and,
- Xcel Energy Inc. (XEL)

Q. Have you reviewed financial data for the Electric Proxy Group?

A. Yes. Page 1 of Schedule 3 contains comparative capitalization and financial statistics for the Electric Proxy Group for the years 2010 – 2014.

As shown on page 1, during the five-year period ending 2014, the achieved earnings rate on book common equity for the group averaged 8.60%. The average common equity ratio based upon permanent capital (excluding short-term debt) was 49.38%, and the average dividend payout ratio was 61.09%. Total debt outstanding as a percentage of EBITDA for the years 2010-2014 ranged between 3.56 and 4.05 times, averaging 3.78 times, while funds from operations relative to total debt ranged between 22.93% and 25.03%, averaging 23.82%.

Q. Are the cost of common equity models that you use market-based models?

A. Yes. The DCF model is market-based in that market prices are utilized in developing the dividend yield component of the model. The RPM and CAPM are also market-based in that the bond/issuer ratings and expected bond yields/risk-free rate used in the application of the RPM reflect the market's assessment of bond/credit risk. In addition, the use of beta coefficients to determine the equity risk premium reflects the market's assessment of market/systematic risk as beta coefficients are derived from regression analyses of market prices. Moreover, market prices are used in the development of the monthly returns and equity risk premiums used in the Predictive Risk Premium Model ("PRPM"). Selection of the companies in the Non-Price Regulated Proxy Group are market-based in that the selection criteria are based upon statistical regression analyses of market prices.

A. DCF Model

Q. What is the theoretical basis of the DCF model?

A. The theoretical basis of the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investor's capitalization rate. DCF theory assumes that an investor buys a stock for an expected total return rate, which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate). Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, i.e., the total common equity return rate expected by investors for the proxy group.

Q. Which version of the DCF model do you use?

A. I utilize the single-stage constant growth DCF model. The single-stage DCF model is expressed as:

$$K = (D_1 / P_0) + g$$

Where:
- K = Cost of Equity Capital
- D_1 = Expected Dividend Per Share in one year
- P_0 = Current Market Price
- g = Expected Dividend Per Share Growth

Q. Please describe the dividend yield you used in your application of the DCF model.

A. The unadjusted dividend yields are based upon a recent (January 29, 2016) dividend divided by the average of closing market prices for the sixty days ending January 29, 2016 as shown in Column 1 on page 1 of Schedule 4.

Q. Please explain the adjusted dividend yield shown on page 1 of Schedule 4, Column 7.

A. Because dividends are paid periodically (quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model. DCF theory calls for the use of the full expected growth rate in calculating the dividend yield component of the model. However, since the various companies in the Electric Proxy Group increase their quarterly dividend at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. This is a conservative approach, which does not overstate the dividend yield that should be representative of the next twelve-month period. Therefore, the actual average dividend yields in Column 1 on page 1 of Schedule 4 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. Please explain the basis of the growth rates of the Electric Proxy Group that you use in your application of the DCF model.

A. Individual investors, with more limited resources than institutional investors, are likely to rely upon widely available financial information services, such as *Value Line*, Reuters, Zacks and Yahoo! Finance. Investors recognize that such analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as a company's ability to effectively manage the effects of changing laws and regulations and ever changing economic and market conditions.

Security analysts' earnings expectations have a significant influence on market prices and are therefore reasonable indicators of investor expectations. As noted by Morin:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g [growth].[20]

Over the long run, there can be no growth in DPS without growth in EPS. Thus, the use of expected earnings growth rates in a DCF analysis provides a better matching between investors' market price appreciation expectations and the growth rate component of the

[20] Morin, 298-303.

DCF. Therefore, I have relied upon security analysts' five-year forecasts of EPS growth in my application of the DCF model.

Q. Please summarize your DCF model results.

A. As shown on page 1 of Schedule 4, the mean result of the single-stage DCF model is 8.87%, while the median is 8.72%. I have averaged these two results in arriving at a conclusion of a DCF-indicated common equity cost rate of 8.80% for the Electric Proxy Group. By doing so, I have not only considered the DCF results for each company, but have mitigated the effect of outliers on both the high and the low side.

Q. Please comment upon the applicability of the DCF model in establishing a cost of common equity for the company.

A. The DCF model has a tendency to misspecify investors' required common equity return rate when the market value of common stock differs significantly from its book value. Mathematically, because the "simplified" DCF model traditionally used in rate regulation assumes a market-to-book ratio of one, it understates or overstates investors' required return rate when market value exceeds or is less than book value, respectively. It does so because, in many instances, market prices reflect investors' assessments of long-range market price growth potential (consistent with the infinite investment horizon implicit in the standard regulatory version of the DCF model) not fully reflected in analysts' shorter range forecasts of future growth in EPS, an accounting proxy. Thus, the market-based DCF model will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation. For example, in recent years the market values of electric utilities' common stocks have been well in excess of their book values, ranging between 104.38% and 160.88% for the five years ending 2014 (see page 1 of Schedule 3).

Under DCF theory, the rate of return investors require is related to the market price paid for a security. Thus, market prices form the basis of investment decisions and investors' expected rates of return. In contrast, a regulated utility is generally limited to earning on a net book value (depreciated original cost) rate base. Although market prices are significantly influenced by analysts' EPS growth forecasts, market values can diverge from book values for a myriad of macroeconomic reasons including, but not limited to, EPS and DPS expectations, merger or acquisition expectations, interest rates, investor sentiment, unemployment levels, monetary policy, fiscal policy, etc.

Traditional rate base/rate of return regulation, where a market-based common equity cost rate is applied to a book value rate base, presumes that market-to-book ratios are at unity or 1.00. However, there is ample empirical evidence over sustained periods which demonstrates that this is an incorrect presumption. Because market-to-book ratios of unity or 1.00 are rarely the case as discussed above, regulatory allowed ROEs, which establish earnings by design, have a limited effect on utilities' market/book ratios as the market prices of utility common stocks are also influenced by factors beyond the direct influence of the regulatory process.

As noted by Phillips:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.[21]

In addition, Bonbright states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market.* In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels.[22]

Simply put, capital market dynamics are generally independent of the effects of regulatory decisions, but are influenced to a certain extent by regulatory decisions.

Q. Is it reasonable to expect the market values of utilities' common stocks to continue to sell well above their book values?

A. Yes. Market-to-book ratios of regulated utilities vary from year to year, due to such influences as the effects of the "Great Recession," subsequent economic and capital market recovery and turmoil, global economic and geopolitical conditions, and the like. In my opinion, the common stocks of utilities will continue to sell substantially above their book values, on average, because many investors will likely continue to commit a greater percentage of their available capital to common stocks in view of lower interest rate alternative investment opportunities in today's markets. The recent past and current

---

21 Phillips, Charles F., The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) 395.

22 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988) 334. (italics added).

capital market environment is in stark and historical contrast to the late 1970's and early 1980's when very high (by historical standards) yields on secured debt instruments in public utilities were available. Despite the fact that the market declined to a low in March 2009 as the "Great Recession" unfolded and the U.S. is now recovering from the "Great Recession," the majority of utility stocks, on average, have continued to sell at market prices well above their book value. As previously discussed, such sustained high market-to-book ratios have been influenced by factors other than fundamentals such as actual and reported growth in EPS and DPS, and warrant further consideration in setting an authorized ROE.

Q. Can the under- or overstatement of the investors' required rate of return by the DCF model be demonstrated mathematically?

A. Yes. Page 2 of Schedule 4 demonstrates how an average market-based DCF cost rate of 8.87% based upon the Electric Proxy Group applied to a book value which is below market value will understate the investors' required return on market value. As shown, there is no realistic opportunity to earn the expected market-based rate of return on book value. In Column A, investors expect an 8.87%[23] return on a market price of $49.11,[24] or $4.356. In Column B, when the same return, 8.87%, is applied to a book value of $28.99,[25] a return of $2.571 results. Both columns show that the same $1.856[26] dividend is indicated, but when the 8.87% is applied to book value, the investor only has the opportunity for $0.715 in market appreciation, or 1.46%. Of course, the converse is also

---

[23] Average DCF cost rate from Schedule 3, p. 1.

[24] Average market price of the Electric Proxy Group derived from Schedule 9, p. 3.

[25] Average book value of the Electric Proxy Group derived from Schedule 9, p. 3.

[26] Average adjusted dividend yield for the Electric Proxy Group derived from Schedule 3, p. 1.

true. When the market-to-book value is below 1, the DCF cost rate will overstate the investors' required return on market value.

Hence, it is clear that the DCF model misspecifies, that is, it either understates or overstates investors' required cost of common equity capital when market values exceed or are less than their underlying book values. Therefore, as stated above, in order to add reliability to the estimation of the cost of common equity, multiple cost of common equity models should be relied upon, rather than exclusive reliance upon the DCF model, when estimating investors' expectations.

In view of the foregoing, at this time the traditional application of the DCF misspecifies investors' required return. Specifically, it understates investors' required return because of the confluence of recently rising and volatile market prices, the use of accounting measures as proxies for capital appreciation in the DCF, and the expected continued rise in interest rates and capital costs discussed above. The magnitude of this understatement can be found in the difference between the 5.09% average expected growth in market value, i.e., growth in EPS, shown in Column A on page 2 of Schedule 4, and the growth in market value of 1.46%, shown in Column B, when the 8.87% DCF cost rate is applied to book value, or up to approximately 360 basis points. Coupled with the added reliability and accuracy that the use of multiple cost of common equity models provides in the estimation of the cost of common equity, it is more imperative than ever to not give exclusive or even primary reliance to the DCF analysis at this time. In fact, in my opinion, it would be inappropriate to give any greater weight to the DCF analysis than I already have in deriving my multi-model return on common equity recommendation.

B. RPM

Q. Please describe the theoretical basis of the RPM.

A. The RPM is based upon the basic financial principle of risk and return, namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are last in line in any claim on an entity's assets and earnings as previously discussed. Thus, investors require higher returns from investment in common stocks than from investment in bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, the investor required common equity return cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds, either historically or prospectively, and then use that premium to derive a cost rate of common equity. According to the RPM, the cost of common equity equals the expected cost rate for long-term debt capital plus a risk premium over that cost rate to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on a corporation's assets and earnings.

Q. Please explain how you derived your indicated cost of common equity based upon the RPM.

A. I relied upon the results of the application of two risk premium methods. The first method is PRPM, while the second method is a risk premium model using a total market approach.

Q. Please explain the PRPM.

A. The PRPM, published in the Journal of Regulatory Economics ("JRE")[27] and The Electricity Journal ("TEJ"),[28] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")."[29] Engle found that the volatility in market prices, returns, and equity risk premiums also clusters over time, making them highly useful in predicting future levels of risk and risk premiums.

The PRPM estimates the risk/return relationship directly as the predicted equity risk premium is generated by the prediction of volatility, or risk. Thus, the PRPM is not based upon an estimate of investor behavior, but rather upon the evaluation of the actual results of that behavior, i.e., the variance of historical equity risk premiums.

The inputs to the model are the historical monthly returns on the common shares of each utility in the Electric Proxy Group minus the historical monthly yield on long-term U.S. Treasury securities through January 2016. Using a generalized form of ARCH, known as GARCH,[30] each electric utility's projected equity risk premium was calculated using Eviews© statistical software. When the GARCH model is applied to the historical return

---

27 Autoregressive Conditional Heteroskedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities," Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. The Journal of Regulatory Economics (December 2011), 40:261-278.

28 "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", Pauline M. Ahern, Richard A. Michelfelder, Ph.D., Rutgers University, Dylan W. D'Ascendis, and Frank J. Hanley, The Electricity Journal (May 2013).

29 www.nobelprize.org

30 The GARCH model, or Generalized Autoregressive Conditional Heteroskedasticity process, is an econometric term developed by Dr. Engle in 1982 to describe a method to estimate volatility in financial and capital markets. The general process for a GARCH model involves three steps: 1) estimating a best fitting autoregressive model; 2) computing autocorrelations of the error term; and 3) testing for significance. GARCH models are used by financial professionals in areas including, but not limited to trading, investing, and hedging.

data, it produces a predicted GARCH variance series[31] and a GARCH coefficient.[32] The forecasted thirty-year U.S. Treasury Bond (Note) yield of 3.68% is based upon the consensus forecast for the six quarters ending with the second quarter 2017 derived from the February 1, 2016 *Blue Chip* averaged with the long-range forecasts for 2017-2021 and 2022-2026 from the December 1, 2015 *Blue Chip.*[33] As shown on page 2 of Schedule 5, the mean PRPM indicated common equity cost rate is 10.67% for the Electric Proxy Group, while the median is 10.86%. Consistent with my reliance upon the average of the mean and median DCF results, I use the average of the mean and median PRPM results of 10.77%[34] as the indicated PRPM cost rate.

Q. Please explain the total market approach RPM.

A. The total market approach RPM adds a prospective public utility bond yield to the average of: 1) an equity risk premium derived from a beta-adjusted total market equity risk premium; 2) an equity risk premium based upon the S&P Utilities Index; and 3) an equity risk premium based upon the authorized returns for electric companies over Moody's A-rated public utility bonds

Q. Please explain the basis of the prospective public utility bond yield of 5.51% applicable to the Electric Proxy Group shown on line 5 of page 3 of Schedule 5.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital (including common equity cost rate) are prospective in nature, a prospective yield on similarly-rated long-term debt

---

31 Illustrated in Columns 1 and 2 on page 2 of Schedule 5.
32 Illustrated in Column 4 on page 2 of Schedule 5.
33 See Schedule 5, pp. 9-10.
34 (10.77% = (10.67% + 10.86%) / 2).

is essential. Because *Blue Chip* does not publish consensus forecasts for the Moody's A-rated public utility bond yield, I began with the February 1, 2016 *Blue Chip*'s consensus forecast of about fifty economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2017 averaged with the long-range forecasts for 2017-2021 and 2022-2026 from the December 1, 2015 *Blue Chip*.[35] As shown on Line 1 of page 3 of Schedule 5, the average expected yield on Moody's Aaa-rated corporate bonds is 4.78%. Next, in order to derive a prospective Moody's A2-rated public utility bond yield, an upward adjustment of 0.33%, the average spread between Moody's Aaa-rated corporation bond yields and Moody's A-rated public utility bond yields for the three months ending January 2016[36] must be made to the average Aaa corporate bond yield which results in a bond yield of 5.11% applicable to a Moody's A2 public utility bond.[37]

Likewise, since the Electric Proxy Group's average Moody's long-term issuer rating is A3, as shown on page 5 of Schedule 5, a further adjustment of 0.40%,[38] or one-third of the average spread of 1.20% between Moody's A-rated and Baa-rated public utility bonds for the three months ending January 2016, to the prospective Moody's A2 public utility bond yield of 5.11% is necessary to make the prospective bond yield applicable to the Electric Proxy Group's average A3 long-term issuer rating.[39] Adding the 0.40% to the

---

35 Schedule 5, pp. 9-10.
36 Schedule 5, p. 4.
37 (5.11% = 4.78% + 0.33%). As shown on Line 3 and explained in Note 2 on page 3 of Schedule 5.
38 0.40% = (1/3) * 1.20%. Please see page 4 of Schedule 5 for the derivation of the 1.20%.
39 As detailed in Note 3 on page 3 of Schedule 5.

5.11% prospective A2 public utility bond yield results in a 5.51% expected bond yield for the Electric Proxy Group as shown on Line 4.[40]

Q. Please explain the basis of the beta derived equity risk premium.

A. The total beta derived equity risk premium is based upon an average of:

1) The long-term arithmetic mean historical market equity risk premium;
2) A predicted equity risk premium based upon the PRPM;
3) A forecasted market risk premium based upon *Value Line's* projected market appreciation and dividend yield; and,
4) A forecasted equity risk premium based upon the S&P 500 market-value weighted projected market appreciation and dividend yield.

Each of these equity risk premiums is described in turn.

Q. How did you derive the long-term historical market equity risk premium?

A. To derive an historical market equity risk premium, I used the most recent Morningstar data on holding period returns for the large company common stocks from the Ibbotson® SBBI® 2015 Classic Yearbook – Market Results for Stocks, Bonds, Bill and Inflation 1926 – 2014 ("SBBI – 2015")[41] and the average historical yield on Moody's Aaa and Aa-rated corporate bonds for the period 1928-2014. The use of holding period returns over a very long period of time is useful because it is consistent with the long-term investment horizon of investing in a going concern, i.e., a company expected to operate in perpetuity.

---

40 5.51% = 5.11% + 0.40%. As shown on Line 5 and explained in Note 3 on page 3 of Schedule 5.

41 Ibbotson® SBBI® 2015 Classic Yearbook – Market Results for Stocks, Bonds, Bills and Inflation 1926 – 2014, Morningstar, Inc., 2015, 153.

Morningstar's long-term arithmetic mean monthly total return rate on large company common stocks is 11.79% and the long-term arithmetic mean monthly yield on Moody's Aaa and Aa-rated corporate bonds is 6.18%. The resultant long-term historical equity risk premium on the market as a whole is 5.61%.[42]

I used arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for Moody's Aaa/Aa corporate bonds because they are appropriate for cost of capital purposes as noted in the SBBI – 2015.[43] The use of arithmetic mean return rates and yields are appropriate because ex-post (historical) total returns and equity risk premiums differ in size and direction over time, providing insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. Absent such valuable insight into the potential variance of returns, investors cannot meaningfully evaluate prospective risk. If investors alternatively relied upon the geometric mean of ex-post equity risk premiums, they would have no insight into the potential variance of future returns because the geometric mean relates the change over many periods of time to a constant rate of change, thereby obviating the period-to-period fluctuations, or variance, critical to risk analysis.

Q. Please explain the derivation of a PRPM market equity risk premium.

A. I used the same PRPM approach described previously to develop a second market equity risk premium estimate. The inputs to the model are the historical monthly returns on large company common stocks from SBBI – 2015 minus the monthly yields on Aaa and Aa corporate bonds during the period from January 1928 through December 2015. Using

[42] As explained in note 1 on page 8 of Schedule 5.
[43] SBBI – 2015, 153.

the previously discussed generalized form of ARCH, known as GARCH, the market's projected equity risk premium was determined using Eviews© statistical software. The resulting predicted market equity risk premium based upon the PRPM is 7.38%.[44]

Q. Please explain the derivation of a projected equity risk premium based upon *Value Line* data.

A. As noted previously, because both ratemaking and the cost of capital, including the cost rate of common equity, are prospective, the use of a prospective market equity risk premium is essential. The derivation of the forecasted or prospective market equity risk premium can be found in Note 3 on page 8 of Schedule 5. Consistent with the development of the dividend yield component of my DCF analysis, the third prospective market equity risk premium is derived from an average of the three to five-year estimated median market price appreciation potential by *Value Line* plus an average of the median estimated dividend yield for the common stocks of the approximately 1,700 firms covered in *Value Line*'s Standard Edition, both for the thirteen weeks ending February 5, 2016.

The average median expected price appreciation is 49%, which translates to a 10.48% annual appreciation and, when added to the average (similarly calculated) median dividend yield of 2.35%, equates to a forecasted annual total return rate on the market as

[44] As shown in Line 2 on page 8 of Schedule 5 and explained in Note 2.

a whole of 12.83%. The forecasted Aaa bond yield of 4.78%[45] is deducted from the total market return of 12.83%, resulting in an equity risk premium of 8.05%.[46]

Q. Please explain the derivation of a market equity risk premium based upon the S&P 500 composite index companies.

A. Using data from Bloomberg Financial, a market-value weighted expected total return for the S&P 500 companies can be derived using the expected dividend yields and projected long-term growth in earnings per share as a proxy for capital appreciation. The expected market-value weighted total return for the S&P 500 is 13.46%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 4.78% results in an 8.68% projected market equity risk premium.[47]

Q. What is your conclusion of the market equity risk premium for your total market approach RPM?

A. It is 7.43% as shown on Line 5 on page 8 of Schedule 5. In arriving at this conclusion, I averaged: 1) the historical market equity risk premium of 5.61%; 2) the PRPM based market equity risk premium of 7.38%; 3) the *Value Line*-based forecasted market equity risk premium of 8.05%; and, 3) the S&P 500 market-value weighted projected market equity risk premium of 8.68% shown on Line Nos. 1 through 4 on page 8 of Schedule 5.[48]

Q. What is your conclusion of a beta derived equity risk premium for use in your total market approach RPM analysis?

---

45 See Schedule 5, pp. 9-10.
46 As shown on page 8 of Schedule 5 and explained in Note 3.
47 As shown on Line 4 on page 8 of Schedule 5 and explained in Note 4.
48 (7.43% = (5.61% + 7.38% + 8.05% + 8.68%) / 4).

A. The conclusion of the market equity risk premium of 7.43% is then adjusted by the Electric Proxy Group's beta to account for the market risk of the Electric Proxy Group. Beta is a measure of relative risk to the market as a whole and a logical means by which to allocate an entity's/proxy group's share of the total market's equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule 6, the mean and median *Value Line* and Bloomberg betas for the Electric Proxy Group average 0.69. Multiplying a beta of 0.69 by the market equity risk premium of 7.43%, on Line 4 of page 8 of Schedule 5, results in a beta adjusted equity risk premium of 5.13% for the Electric Proxy Group.[49]

Q. How did you derive the 3.91% equity risk premium based upon the S&P Utility Index and Moody's A-rated public utility bonds?

A. I calculated three estimated equity risk premiums based upon the S&P Utility Index. First, I derived the long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.49% and monthly A-rated public utility bond yields of 6.64% from 1928-2015 to arrive at an equity risk premium of 3.85%.[50] I then applied the PRPM using historical monthly equity risk premiums from January 1928 through January 2016 to arrive at the PRPM derived equity risk premium of 3.90% for the S&P Utility Index.[51] Third, I derived an expected market-value weighted total return on the S&P Utility Index of 9.09% using data from Bloomberg Financial and subtracting the

[49] As shown on Line 7 on page 8 of Schedule 5.
[50] As shown on Line 3 on page 11 of Schedule 5.
[51] As shown on Line 4, on page 11 of Schedule 5.

prospective Moody's A-rated public utility bond yield of 5.11%, resulting in an equity risk premium of 3.98%.[52]

I rely upon the average of the historical (3.85%), the PRPM (3.90%) and S&P Utility Index (3.98%) derived equity risk premiums, which is 3.91%.[53]

Q. How did you derive an equity risk premium of 5.19% based on authorized ROEs for electric companies?

A. The equity risk premium of 5.19% shown on Line 3, page 7 of Schedule 5 is the result of a regression analysis based on regulatory awarded returns on common equity related to the yields on A-rated public utility bonds. That analysis is summarized on page 12 of Schedule 5, which presents the graphical results of a regression analysis of 1,098 rate cases for electric utility companies which were fully litigated during the period from January 1, 1980 through December 31, 2015. The data used were the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision.[54] An inverse relationship between the yield on A-rated public utility bonds and the equity risk premium is clearly visible in the chart on page 12. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with regulatory financial literature on the subject.[55] Given the expected A-rated utility bond yield of 5.11%, it can be interpolated that the indicated

52 As shown on Line 5 on page 11 of Schedule 5.

53 (3.91% = ((3.85% + 3.90% + 3.98%) / 3).

54 The implied equity risk premium is calculated by subtracting the prevailing yield on Moody's A rated public utility bonds from the authorized return on common equity for each case.

55 Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, 89-95.

equity risk premium applicable to that bond yield is 5.19%, which is shown on Line 3, page 5 of Schedule 5.

Q. What is your conclusion of an equity risk premium for use in your adjusted total market approach RPM analysis?

A. The equity risk premium applicable to the Electric Proxy Group is 4.74%,[56] derived by averaging the beta-derived premium of 5.13%, the equity risk premium of 3.91% based upon the holding period returns of public utilities with Moody's A-rated bonds and the equity risk premium of 5.19% based upon the regression analysis of electric utility authorized returns on common equity.

Q. What is the indicated RPM common equity cost rate based upon the adjusted total market approach?

A. It is 10.25% for the Electric Proxy Group as shown on Line 7 on Schedule 5, page 3.

Q. What are the results of your application of the PRPM and the total market approach RPM?

A. As shown on page 1 of Schedule 5, the indicated RPM-derived common equity cost rate is 10.51%,[57] derived by averaging the PRPM result of 10.77% with that based upon the adjusted total market approach, 10.25%.

C. CAPM

Q. Please explain the theoretical basis of the CAPM.

---

[56] (4.74% = (5.13% + 3.91% + 5.19) / 3).

[57] (10.51% = ((10.77% + 10.25%) / 2).

A. CAPM theory defines risk as the covariability of a security's returns with the market's returns as measured by beta coefficient (β). A beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a beta coefficient greater than 1.0 indicates greater variability than the market a whole.

The CAPM assumes that all other risk, i.e., all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors require compensation only for systematic risk that is the result of macroeconomic and other events that affect the returns on all assets. The CAPM is applied by adding a risk-free rate of return to a market risk premium, which is adjusted by the beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

Where: R_s = Return rate on the common stock

R_f = Risk-free rate of return

R_m = Return rate on the market as a whole

β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta coefficient is related to security returns, the empirical Security

Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML. Morin[58] states:

> With few exceptions, the empirical studies agree that ... low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta\,(R_M - R_F) + (1-x)\;\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship. Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\;\beta(R_M - R_F)$$[59]

In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the Electric Proxy Group and averaged the results.

Q. Please describe your selection of beta coefficients for your CAPM analyses.

A. I rely upon an average of the adjusted beta coefficients published by *Value Line* and by Bloomberg Financial. While both of those services adjust their calculated (or "raw") beta coefficients to reflect the tendency of the beta coefficient to regress to the market mean of 1.00, *Value Line* calculates its beta coefficient over a five-year period, while Bloomberg's calculation is based upon two years of data.

Q. Please describe your selection of a risk-free rate of return for your CAPM analyses.

---

58 Morin 175.

59 Morin 190.

A. As shown in Column 5, Schedule 6, the risk-free rate adopted for both applications of the CAPM is 3.68%. The risk-free rate of 3.68% is based upon the average of the consensus forecast of 30-year Treasury bond rates for the six quarters ending with the second calendar quarter of 2017 from the February 1, 2016 *Blue Chip* averaged with the long-range forecasts for 2017-2021 and 2022-2026 from the December 1, 2015 *Blue Chip,*[60] as detailed in Note 2.

Q. Why is the yield on long-term U.S. Treasury Bonds appropriate for use as the risk-free rate?

A. The yield on long-term U.S. Treasury T-Bonds is almost risk-free and its term is consistent with: 1) the long-term cost of capital to public utilities measured by the yields on A-rated public utility bonds; 2) the long-term investment horizon inherent in utilities' common stock; and 3) the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile.

Q. Please explain the estimation of the expected equity risk premium for the market.

A. The basis of the market equity risk premium is explained in detail in Note 1 of Schedule 6. It is derived from an average of:

1) The three to five-year median total market price appreciation projections for the thirteen weeks ending February 5, 2016 reported by *Value Line;*

[60] See Schedule 5, pp. 9-10.

2) The arithmetic mean monthly equity risk premiums of large company common stocks relative to long-term U.S. Treasury bond income yields from SBBI-2015 from 1926 to 2014;

3) The PRPM predicted market equity risk premium, using monthly equity risk premiums for large company common stocks relative to long-term U.S. Treasury securities from January 1926 through December 2015;

4) The results of a regression analysis of the monthly equity risk premiums of large company common stocks relative to long-term U.S. Treasury bond income yields from SBBI-2015 from 1926 to 2014; and,

5) The market-value weighted projected total return on the S&P 500 minus the projected risk-free rate.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the projected 3.68% risk-free rate, discussed above, from the *Value Line* projected total annual market return of 12.83%, also discussed above, resulting in a forecasted total market equity risk premium of 9.15%.[61]

The long-term income return on U.S. Government Securities of 5.23% was deducted from the SBBI – 2015[62] monthly historical total market return of 12.07% resulting in an historical market equity risk premium of 6.84%.[63]

---

61 (9.15% = 12.83% - 3.68%).

62 SBBI-2015 196-197, 208-209.

63 (6.84% = 12.07% - 5.23%).

The PRPM market equity risk premium is 8.32%, derived using the PRPM, discussed above, relative to the yields on long-term U.S. Treasury securities from January 1926 through December 2015.

To derive the regression analysis-derived market equity risk premium of 8.34%, I used monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government Securities from SBBI-2015. The relationship between interest rates and the market equity risk premium was modeled using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on long-term U.S. Government Securities as the independent variable. I used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the U.S. Government Securities yield:

$$RP = \alpha + \beta\ (R_f)$$

The S&P 500 market-value weighted projected market equity risk premium of 9.78% is derived by subtracting the 3.68% projected risk-free rate, discussed above, from the projected total return of 13.46%, also discussed above.[64]

These five market equity risk premiums result in an average total market equity risk premium of 8.49%.[65]

Q. What are the results of your applications of the traditional and empirical CAPM to the Electric Proxy Group?

---

[64] (9.78% = 13.46% - 3.68%).

[65] (8.49% = ((9.15% + 6.84% + 8.32% + 8.34% + 9.78%) / 5).

A. As shown on page 1 of Schedule 6, the mean CAPM/ECAPM cost rate is 9.83% while the median CAPM/ECAPM cost rate is 9.94%, averaging 9.89%. Consistent with my reliance upon the average of the mean and median results of the DCF discussed above, the Electric Proxy Group's indicated common equity cost rate based upon my CAPM analyses is 9.89%.

V. COMMON EQUITY COST RATE FINDINGS FOR THE NON-PRICE REGULATED PROXY GROUP

Q. You have also included an analysis of data for a Non-Price Regulated Proxy Group. Please explain.

A. Neither the *Hope* nor *Bluefield* cases specify that comparable risk companies have to be regulated utilities. Since rate regulation is a substitute for the competition of the marketplace, non-price regulated firms operating in the competitive marketplace are an excellent proxy if a group can be selected to be comparable in total risk to the Electric Proxy Group upon whose market data I rely to estimate the cost of common equity. As explained below, the selection criteria I utilized are theoretically and empirically sound and produced results for a non-regulated proxy group which is comparable in total risk to the Electric Proxy Group.

Q. Please explain how you chose the Non-Price Regulated Proxy Group.

A. The selection criteria that I utilized for the non-price regulated firms were based upon statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks, i.e., five years, from the market prices paid by investors. *Value Line* unadjusted betas were used as a measure of systematic risk, while the standard errors of the regressions giving rise to those beta coefficients are a measure of unsystematic or firm-specific risk reflecting the extent to which events specific to a firm's operations affect its stock price. In essence, companies with similar betas and standard errors of the regression have similar total investment risk. The criteria used to select the Non-Price Regulated Proxy Group were:

1) The unadjusted beta coefficients from the *Value Line* regressions must lie within plus or minus two standard deviations of the average unadjusted beta coefficients of the Electric Proxy Group;
2) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Electric Proxy Group;
3) The non-regulated firms must be covered by *Value Line* (Standard Edition); and
4) The firms must be domestic, non-price regulated companies, i.e., non-utilities.

The basis of selection and the comparison group's regression statistics are shown in Schedule 7. The following seventeen companies met these criteria:

- A.J. Gallagher Co. (AJG);
- Becton Dickinson (BDX);
- Brown-Forman 'B' (BFB);
- Ball Corp. (BLL);
- Costco Wholesale Corp. (COST);
- Amdocs Ltd. (DOX);
- Ecolab Inc. (ECL);
- Erie Indemnity Co. (ERIE);
- Hormel Foods Corp. (HRL);
- Lilly (Eli) and Co. (LLY);
- The Progressive Corp. of OH (PGR);
- Philip Morris Int'l, Inc. (PM);
- Stericycle Inc. (SRCL);
- Sysco Corp. (SYY);

- The Travelers Cos., Inc. (TRV);
- Waste Connections, Inc. (WCN); and
- W.R. Berkley (W.R.) Corp. (WRB).

Q. Did you calculate common equity cost rates using the DCF, RPM and CAPM for the Non-Price Regulated Proxy Group?

A. Yes. Because the DCF, RPM and CAPM have been applied in an identical manner as described above relative to the market data of the Electric Proxy Group, I will not repeat the details of the rationale and application of each model shown on page 1 of Schedule 8. I should note, however, that, in the application of the RPM, I did not use public utility-specific equity risk premiums nor apply the PRPM to the individual companies.

Page 2 of Schedule 8 contains the derivation of the DCF cost rates. As shown, the average of the mean and median DCF cost rates for the Non-Price Regulated Proxy Group is 11.16%.

Pages 3 through 5 of Schedule 8 contain the data and calculations relating to the 11.29% RPM cost rate for the Non-Price Regulated Proxy Group. As shown on Line 1 of page 3, the consensus prospective yield on Moody's Baa-rated corporate bonds of 5.83% is based upon the forecasted yields for the six quarters ending with the second quarter of 2017 from the February 1, 2016 *Blue Chip*, averaged with the long-range forecasted yields for 2017-2021 and 2022-2026 also from the December 1, 2015 *Blue Chip*.[66] Since the Non-Price Regulated Proxy Group members have an average Moody's long-term issuer rating of A3 as shown on page 4 of Schedule 8, a <u>downward</u> adjustment of 0.71% to the

[66] See Schedule 5, pp. 9-10.

prospective bond yield is necessary to reflect the difference in ratings[67] which results in a projected Baa corporate bond yield of 5.12%. When the beta-adjusted risk premium of 6.17%[68] relative to the Non-Price Regulated Proxy Group is added to the prospective A3-rated corporate bond yields of 5.12%, the indicated RPM cost rate is 11.29%.

Page 6 of Schedule 8 contains the details of the application of the traditional CAPM and ECAPM to the Non-Price Regulated Proxy Group. As shown, the mean and median traditional CAPM and ECAPM results are 10.89%/10.83% for the Non-Price Regulated Proxy Group which, when averaged, result in an indicated CAPM cost rate of 10.86%.[69]

Q. What is your conclusion of the cost rate of common equity for the Non-Price Regulated Proxy Group?

A. It is 11.13%, as shown on page 1 of Schedule 8. The results of the DCF, RPM and CAPM applied to the Non-Price Regulated Proxy Group are 11.16%, 11.29% and 10.86%, respectively. Based upon these results, I will rely upon the average of the mean and median results of the three models, which is 11.13% for the Non-Price Regulated Proxy Group.

Q. Please summarize the indicated common equity cost rate based upon your proxy group findings.

A. As shown on Schedules 4, 5, 6 and 8, indicated cost rates of common equity were derived using the DCF, CAPM and RPM methods applied to the market data of an Electric Proxy Group and a Non-Price Regulated Proxy Group similar in total risk to the Electric Proxy

67 As shown on Line 2 and explained in Note 2 on page 4 of Schedule 7.
68 Derived on Schedule 7, p. 5.
69 (10.86% = (10.89% + 10.83%) / 2).

Group. Based upon an average of the mean and median of these results, I conclude that the indicated cost rate of common equity is 10.14%, rounded to 10.15%. In averaging the mean and median, I have not only considered the results of each cost of common equity model, but have mitigated the effect of outliers on either the high or the low side. Note that the indicated common equity cost rate of 10.15% is exclusive of the recognition of flotation costs and necessary company-specific adjustments for relative size and credit risk.

VI. ADJUSTMENTS

A. Flotation Cost Adjustment

Q. What are flotation costs?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the essential costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.).

Q. Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. It is important because there is no other mechanism in the ratemaking paradigm by which such costs can be recovered. Because these costs are real and legitimate, recovery of these costs should be permitted. As noted by Dr. Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs....

> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[70]

Q. Should flotation costs be recognized only when there is an equity issuance during the test year or shortly after the test year?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to the common equity cost rate even when there has not been an issuance during the test year or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, \$0.95, to earn more than 10% to net back to the investor a fair return on that

[70] Morin 321.

dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. Do the common equity cost rate models you use in your analyses already reflect investors' anticipation of flotation costs?

A. No. These models assume no transaction costs. The literature is quite clear that these costs are not reflected in market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[71] In addition, Dr. Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[72] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. How did you calculate the flotation cost allowance?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves as well as Morin. The flotation cost adjustment recognizes the costs of issuing equity that were incurred by FirstEnergy Corp. since August 2003. Based upon the issuance costs shown on page 1 of Schedule 9, an adjustment of 0.27% is required to reflect the flotation costs applicable to the Electric Proxy Group as shown on Schedule 2 and Table 2 below:

---

71 Brigham and Daves 342.
72 Morin 327-30.

Table 2

	Electric Proxy Group
Discounted Cash Flow Model	8.80%[73]
Range: 6.33% - 12.31% (midpoint: 9.32%)	
Risk Premium Model	10.51%
Range: 10.25% - 10.77% (midpoint: 10.51%)	
Capital Asset Pricing Model	9.89%
Range: 8.53% - 10.83% (midpoint: 9.68%)	
Cost of Common Equity Models Applied to the Non-Price Regulated Proxy Group	11.13%
Range: 10.86% - 11.29% (midpoint: 11.07%)	
Indicated Common Equity Cost Rate Before Adjustment	10.15%[74]
Flotation Costs	0.27%
Indicated Common Equity Cost Rate for the Electric Proxy Group before Company-Specific Risk Adjustments	10.42%

B. Adjustments For Company-Specific Risk Factors

Q. Does Met-Ed face any unique business risk relative to the Electric Proxy Group?

A. Yes. Met-Ed is smaller than the average company in the Electric Proxy Group based upon estimated market capitalization as shown in Table 3 below:

73 As discussed earlier in my testimony, the current DCF model understates the required return on common equity by as much as 360 basis points due to a highly unusual and, in all likelihood temporary, convergence of historically anomalous market conditions. Accordingly, the results of that model should be given only very limited weight in deriving a reasonable ROE in this proceeding.

74 Based upon an average of the mean and median of the results of the DCF, CAPM and RPM methods applied to the market data of the Electric Proxy Group and a Non-Price Regulated Proxy Group, 10.14%, rounded to 10.15%. By doing so, I have not only considered the results of each cost of common equity model, but have mitigated the effect of outliers on either the high or the low side.

Table 3

	Market Capitalization (1) ($ Millions)	Times Greater than the Company
Met-Ed	$1,337.390	
Electric Proxy Group	$9,647.332	7.2X

(1) From page 1 of Schedule 10.

As shown above, Met-Ed's estimated market capitalization of $1.337 billion is much less than the average market capitalization of the Electric Proxy Group, $9.647 billion, as of January 29, 2016. Consequently Met-Ed has greater relative business risk because, all else being equal, size has a bearing on risk. Since investors demand a higher return in compensation for assuming greater risk, Met-Ed's greater relative business risk must be reflected in the cost of common equity derived from the market data of the less business risky Electric Proxy Group.

Q. How does a company's size have a bearing on business risk?

A. Generally because smaller companies are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers can have a greater effect on a small company than on a much bigger company with a larger, more diverse, customer base.

Further evidence that smaller firms are more risky is the fact that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. The fact that it is the use of funds invested, and not the source of those funds, which gives rise to the risk of any investment is a basic financial principle.[75]

Brigham[76] states:

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what *the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.*

Consistent with the financial principle of risk and return discussed above, such increased risk due to small size must be taken into account in the allowed rate of return on common equity. Therefore, the Commission should authorize a cost of common equity in this proceeding that appropriately reflects Met-Ed's relevant risks, including the impact of its small size.

Q. Is there a way to quantify a business risk adjustment due to Met-Ed's small size relative to the Electric Proxy Group?

A. Yes. An indication of the magnitude of such an adjustment for the greater relative business risk due to smaller relative size is based upon the size premiums for decile portfolios of New York Stock Exchange (NYSE), American Stock Exchange (AMEX) and NASDAQ listed companies for the 1926-2014 period and related data from Duff & Phelps <u>2015 Valuation Handbook Guide to Cost of Capital – Market Results through</u>

---

75 Brealey, Richard A. and Myers, Stewart C., <u>Principles of Corporate Finance</u> (McGraw-Hill Book Company, 1996) 204-205, 229.

76 Brigham, Eugene F., <u>Fundamentals of Financial Management, Fifth Edition</u> (The Dryden Press, 1989) 623 (italics added).

2014 (D&P – 2015). The size premium for the 3rd decile (0.91%) in which the market capitalization of the Electric Proxy Group falls has been compared with the size premium for the 7th decile (1.71%) in which the estimated market capitalization of Met-Ed falls. As shown on page 1 of Schedule 10, the size premium spread between the 3rd and 7th deciles is 0.80%. In view of the foregoing, I am recommending a business risk adjustment of 0.10% to reflect Met-Ed's smaller size relative to the Electric Proxy Group.

Q. Is there a way to quantify a credit risk adjustment due to Met-Ed's Moody's bond rating of Baa1?

A. Yes. Met-Ed's Moody's issuer credit rating is Baa1.[77] In contrast, the average Moody's issuer credit rating for the Electric Utility Group is A3 as shown on page 4 of Schedule 5. Consequently, Met-Ed has greater credit risk than the Electric Proxy Group. An indication of the magnitude of the necessary upward credit risk adjustment to reflect the greater credit risk inherent in a Moody's Baa1 issuer credit rating relative to an A3 issuer credit rating is one-third of a recent three-month average yield spread between Moody's A and Baa2-rated public utility bonds of 1.20%[78] or 0.40%.[79]

VII. CONCLUSION OF COMMON EQUITY COST RATE

Q. What is your recommended common equity cost rate?

A. In view of the foregoing, I have adjusted the flotation cost adjusted indicated common equity cost rate of 10.42% upward by 0.10% to reflect Met-Ed's smaller size relative to the Electric Proxy Group and by 0.40% to reflect its greater credit risk relative to the

[77] Moody's Investor Services, December 10, 2015.
[78] Shown Schedule 5, p. 4.
[79] 0.40% = 1.20% * (1/3).

Electric Proxy Group. These adjustments result in a common equity cost rate applicable to Met-Ed of 10.92%, rounded to 10.90%. Consequently, I recommend that the Commission provide Met-Ed with the opportunity to earn a common equity cost rate of 10.90% on its jurisdictional rate base. My recommendation is derived on Schedule 2 and summarized in Table 4 below:

Table 4

	Electric Proxy Group
Indicated Common Equity Cost Rate for the Electric Proxy Group before Company Specific Risk Adjustments*	10.42%
Business Risk Adjustment	0.10
Credit Risk Adjustment	0.40
Indicated Common Equity Cost Rate After Adjustment	10.92%
Recommended Common Equity Cost Rate	10.90%

* Inclusive of flotation costs.

In my opinion, this return is reasonable, if not conservative, given current capital market conditions and, if achieved, would provide Met-Ed with sufficient earnings to attract necessary new capital.

Q. Does that conclude your direct testimony?

A. Yes.

APPENDIX A

Pauline M. Ahern, CRRA
Partner
Sussex Economic Advisors, LLC

Ms. Ahern has served as a consultant for investor-owned and municipal utilities and authorities for 28 years. As a Certified Rate of Return Analyst (CRRA), she has extensive experience in rate of return analyses, including the development of ratemaking capital structure ratios, senior capital cost rates, and the cost rate of common equity for regulated public utilities. She has testified as an expert witness before 30 regulatory commissions in the U.S. and Canada.

She also maintains the benchmark index against which the American Gas Association's (AGA) Mutual Fund performance is measured. Ms. Ahern has also served as President of the Society of Utility Regulatory and Financial Analysts (SURFA) from 2006-2010 and now sits on its Board of Directors. SURFA is a non-profit organization founded to promote the education and understanding of rate of return analysis which represents utility financial analysts in government, the financial community, industry and academia. She also serves on the Finance/Accounting/Taxation Committees of the National Association of Water Companies. Ms. Ahern is also a member of the Advisory Council, Financial Research Institute, University of Missouri - Robert J. Trulaske, Sr. School of Business. She is also a member of Edison Electric Institute's Cost of Capital Working Group.

PROFESSIONAL HISTORY

Sussex Economic Advisors, LLC (2015 – Present)
Partner

AUS Consultants (1988 – 2015)
Principal

- Offered testimony as an expert witness on the subjects of fair rate of return, cost of capital and related issues before state public utility commissions.
- Provided assistance and support to clients throughout the entire ratemaking litigation process; supervision of the financial analyst and administrative staff in the preparation of fair rate of return and cost of capital testimonies and exhibits which are filed along with expert testimony before various state and federal public utility regulatory bodies as well as the preparation of interrogatory responses, as well as rebuttal exhibits.
- Responsible for the production, publishing, and distribution of the AUS Utility Reports (formerly C. A. Turner Utility Reports), which has provided financial data and related ratios for about 80 public utilities (*i.e.*, electric, combination gas and electric, natural gas distribution, natural gas transmission, telephone, and water utilities, on a monthly, quarterly and annual basis) since 1930. Subscribers include utilities, many state regulatory commissions, federal agencies, individuals, brokerage firms, attorneys, as well as public and academic libraries.
- Responsible for maintaining and calculating the performance of the AGA Index, a market capitalization weighted index of the common stocks of the approximately 70 corporate members of the AGA, which serves as the benchmark for the AGA Gas Utility Index Fund.

Assistant Vice President

- Prepared fair rate of return and cost of capital exhibits which were filed along with expert testimony before various state and federal public utility regulatory bodies; supporting exhibits include the determination of an appropriate ratemaking capital structure and the development of embedded cost rates of senior capital and also support the determination of a recommended return on common equity through the use of various market models, such as, but not limited to, Discounted Cash Flow analysis, Capital Asset Pricing Model and Risk

Premium Methodology, as well as an assessment of the risk characteristics of the client utility.

- Assisted in the preparation of responses to any interrogatories received regarding such testimonies filed on behalf of client utilities. Following the filing of fair rate of return testimonies, assisted in the evaluation of opposition testimony in order to prepare interrogatory questions, areas of cross-examination, and rebuttal testimony and evaluated and assisted in the preparation of briefs and exceptions following the hearing process.
- Submitted testimony before state public utility commissions regarding appropriate capital structure ratios and fixed capital cost rates.

Senior Financial Analyst

- Supervised two analysts and assisted in the preparation of fair rate of return and cost of capital exhibits which are filed along with expert testimony before various state and federal public utility regulatory bodies; the team also assisted in the preparation of interrogatory responses.
- Evaluated the final orders and decisions of various commissions to determine whether further actions were warranted and to gain insight which assisted in the preparation of future rate of return studies.
- Assisted in the preparation of an article authored by Frank J. Hanley and A. Gerald Harris entitled "Does Diversification Increase the Cost of Equity Capital?" published in the July 15, 1991 issue of Public Utilities Fortnightly.

Administrator of Financial Analysis for AUS Utility Reports

- Oversaw the preparation of this monthly publication, as well as the accompanying annual publication, Financial Statistics - Public Utilities.

Financial Analyst

- Assisted in the preparation of fair rate of return studies including capital structure determination, development of senior capital cost rates, determination of an appropriate rate of return on equity, preparation of interrogatory responses, interrogatory questions of the opposition, areas of cross-examination and rebuttal testimony, as well as preparation of the annual publication C. A. Turner Utility Reports - Financial Statistics - Public Utilities.

Research Dept. of the Regional Economics Division of the Federal Reserve Bank of Boston (1973 – 1975)

Research Assistant

- Involved in the development and maintenance of econometric models to simulate regional economic conditions in New England in order to study the effects of, among other things, the energy crisis of the early 1970's and property tax revaluations on the economy of New England. I was also involved in the statistical analysis and preparation of articles for the New England Economic Review. Also, I was Assistant Editor of New England Business Indicators.

Office of the Assistant Secretary for International Affairs, U.S. Treasury Department, Washington, D.C. (1972)

Research Assistant

- Developed and maintained econometric models which simulated the economy of the United States in order to study the results of various alternate foreign trade policies so that national trade policy could be formulated and recommended.

EDUCATION

M.B.A., Rutgers University, High Honors, 1991
B.A., Clark University, Honors, 1973

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Advisory Council
Financial Research Institute
University of Missouri's Trulaske School of Business
Edison Electric Institute
Cost of Capital Working Group
National Association of Water Companies
Member of the Finance/Accounting/Taxation and Rates and Regulation Committees
Society of Utility and Regulatory Financial Analysts
Member, Board of Directors – 2010-2014 President – 2006-2008 and 2008-2010
Secretary/Treasurer – 2004-2006
American Finance Association
Financial Management Association

SPEAKING ENGAGEMENTS

"Leadership in the Financial Services Sector", Guest Professor – Cost of Capital, Business Leader Development Program, Rutgers University School of Business, February 20, 2015, Camden, NJ.

"ROE: Trends & Analysis", American Gas Association, AGA Mini-Forum for the Financial Analysts Community & Finance Committee Meeting, September 11, 2014, The Princeton Club, New York, NY.

Guest Professor, "Measuring Risk", Asset Supervision and Administration Commission of the State Council of the Peoples' Republic of China, Rutgers School of Business, July 21, 2014, New Brunswick, NJ.

Instructor, "Cost of Capital 101", EPCOR Water America, Inc., Regulatory Management Team, June 9, 2014, Phoenix, AZ.

Moderator: Society of Utility Financial Analysts: 46th Financial Forum – "The Rating Agencies' Perspectives: Regulatory Mechanisms and the Regulatory Compact", April 22-25, 2014, Indianapolis, IN.

"The Return on Equity Debate: Its Impact on Budgeting and Investment and Wall Street's View of Risk", National Association of Water Companies – 2014 Indiana Chapter Water Summit, March 13, 2014, Indianapolis, IN.

"Regulatory Training in Financing, Planning, Strategies and Accounting Issues for Publicly- and Privately-Owned Water and Wastewater Utilities", New Mexico State University Center for Public Utilities, October 13-18, 2013, Instructor (Cost of Capital).

"Regulated Utilities – Access to Capital", (panelist) - Innovation: Changing the Future of Energy, 2013 Deloitte Energy Conference, Deloitte Center for Energy Solutions, May 22, 2013, Washington, DC.

"Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) – Advanced Workshop in Regulation and Competition, 32nd Annual Eastern Conference of the Center for Research in Regulated Industries (CRRI), May 17, 2013, Rutgers University, Shawnee on the Delaware, PA.

"Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

"Issues Surrounding the Determination of the Allowed Rate of Return", before the Staff Subcommittee on Electricity of the National Association of Regulatory Utility Commissioners, Winter 2013 Committee Meetings, February 3, 2013, Washington, DC.

"Leadership in the Financial Services Sector", Guest Professor – Cost of Capital, Business Leader Development Program, Rutgers University School of Business, February 1, 2013, Camden, NJ.

"Analyst Training in the Power and Gas Sectors", SNL Center for Financial Education, Downtown Conference Center at Pace University, New York City, December 12, 2012, Instructor (Financial Statement Analysis).

"Regulatory Training in Financing Planning, Strategies and Accounting Issues for Publicly and Privately Owned Water and Wastewater Utilities", New Mexico State University Center for Public Utilities, October 14-19, 2012, Instructor (Cost of Financial Capital).

"Application of a New Risk Premium Model for Estimating the Cost of Common Equity", Co-Presenter with Dylan W. D'Ascendis, CRRA, AUS Consultants, Edison Electric Institute Cost of Capital Working Group, October 3, 2012, Webinar.

"Application of a New Risk Premium Model for Estimating the Cost of Common Equity", Co-Presenter with Dylan W. D'Ascendis, CRRA, AUS Consultants, Staff Subcommittee on Accounting and Finance of the National Association of Regulatory Commissioners, September 10, 2012, St. Paul, MN.

"Analyst Training in the Power and Gas Sectors", SNL Center for Financial Education, Downtown Conference Center at Pace University, New York City, August 7, 2012, Instructor (Financial Statement Analysis).

"Advanced Regulatory Training in Financing Planning, Strategies and Accounting Issues for Publicly and Privately Owned Water and Wastewater Utilities", New Mexico State University Center for Public Utilities, May 13-17, 2012, Instructor (Cost of Financial Capital).

"A New Approach for Estimating the Equity Risk Premium Applied to Public Utilities", before the Finance and Regulatory Committees of the National Association of Water Companies, March 29, 2012, Telephonic Conference.

"A New Approach for Estimating the Equity Risk Premium Applied to Public Utilities", (co-presenter with Frank J. Hanley, Principal and Director, AUS Consultants) before the Water Committee of the National Association of Regulatory Utility Commissioners' Winter Committee Meetings, February 7, 2012, Washington, DC.

"A New Approach for Estimating the Equity Risk Premium Applied to Public Utilities", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University and Frank J. Hanley, Principal and Director, AUS Consultants) before the Wall Street Utility Group, December 19, 2011, New York City, NY.

"Advanced Cost and Finance Issues for Water", (co-presenter with Gary D. Shambaugh, Principal & Director, AUS Consultants), 2011 Advanced Regulatory Studies Program – Ratemaking, Accounting and Economics, September 29, 2011, Kellogg Center at Michigan State University – Institute for Public Utilities, East Lansing, MI.

"Public Utility Betas and the Cost of Capital", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) – Advanced Workshop in Regulation and Competition, 30th Annual Eastern Conference of the Center for Research in Regulated Industries (CRRI), May 20, 2011, Rutgers University, Skytop, PA.

Moderator: Society of Utility and Regulatory Financial Analysts: 43rd Financial Forum – "Impact of Cost Recovery Mechanisms on the Perception of Public Utility Risk", April 14-15, 2011, Washington, DC.

"A New Approach for Estimating the Equity Risk Premium for Public Utilities", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) – Hot Topic Hotline Webinar, December 3, 2010, Financial Research Institute of the University of Missouri.

"A New Approach for Estimating the Equity Risk Premium for Public Utilities", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) before the Indiana Utility Regulatory Commission Cost of Capital Task Force, September 28, 2010, Indianapolis, IN.

Tomorrow's Cost of Capital: Cost of Capital Issues 2010, Deloitte Center for Energy Solutions, 2010 Deloitte Energy Conference, "Changing the Great Game: Climate, Customers and Capital", June 7-8, 2010, Washington, DC.

"A New Approach for Estimating the Equity Risk Premium for Public Utilities", (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) – Advanced Workshop in Regulation and Competition, 29th Annual Eastern Conference of the Center for Research in Regulated Industries (CRRI), May 20, 2010, Rutgers University, Skytop, PA.

Moderator: Society of Utility and Regulatory Financial Analysts: 42nd Financial Forum – "The Changing Economic and Capital Market Environment and the Utility Industry", April 29-30, 2010, Washington, DC.

"A New Model for Estimating the Equity Risk Premium for Public Utilities" (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) – Spring 2010 Meeting of the Staff Subcommittee on Accounting and Finance of the National Association of Regulatory Utility Commissioners, March 17, 2010, Charleston, SC.

"New Approach to Estimating the Cost of Common Equity Capital for Public Utilities" (co-presenter with Richard A. Michelfelder, Ph.D., Rutgers University) - Advanced Workshop in Regulation and Competition, 28th Annual Eastern Conference of the Center for Research in Regulated Industries (CRRI), May 14, 2009, Rutgers University, Skytop, PA.

Moderator: Society of Utility and Regulatory Financial Analysts: 41st Financial Forum – "Estimating the Cost of Capital in Today's Economic and Capital Market Environment", April 16-17, 2009, Washington, DC.

"Water Utility Financing: Where Does All That Cash Come From?", AWWA Pre-Conference Workshop: Water Utility Ratemaking, March 25, 2008, Atlantic City, NJ.

PAPERS

"Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Dylan W. D'Ascendis, and Frank J. Hanley, The Electricity Journal, May, 2013.

"A New Approach for Estimating the Equity Risk Premium for Public Utilities", co-authored with Frank J. Hanley and Richard A. Michelfelder, Ph.D., Rutgers University, The Journal of Regulatory Economics (December 2011), 40:261-278.

"Comparable Earnings: New Life for Old Precept" co-authored with Frank J. Hanley, Financial Quarterly Review, (American Gas Association), Summer 1994.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Arizona Water Company	08/15	Arizona Water Company	W-01445A-15-0277	Return on Equity
EPCOR Water Arizona, Inc.	03/14	EPCOR Water Arizona, Inc.	WS-01303A-14-0010	Return on Equity
Arizona Water Company	04/12	Arizona Water Company - Eastern Group	W-01445A-11-0310	DSIC Mechanism - Credit Quality; Return on Equity
Chaparral City Water Company	04/13	Chaparral City Water Company	W-02113A-13-118	Return on Equity
Arizona Water Company	08/12	Arizona Water Company - Northern Group	W-01445A-12-0348	Return on Equity
Bermuda Water Co.	09/11	Bermuda Water Co.	W-01812A-10-0521	Return on Equity
Arkansas Public Service Commission				
United Water Arkansas, Inc.	03/10	United Water Arkansas, Inc.	09-130-U	Fair Rate of Return
United Water Arkansas, Inc.	12/06	United Water Arkansas, Inc.	06-160-U	Fair Rate of Return
United Water Arkansas, Inc.	09/03	United Water Arkansas, Inc.	03-161-U	Return on Equity
Arkansas Western Gas Company d/b/a Associated Natural Gas Company	02/97	Associated Natural Gas Company	97-019-U	Capital Structure
Arkansas Western Gas Company	02/97	ANG Division – Arkansas	97-019-I	Capital Structure
Arkansas Western Gas Company	02/96	ANG Division – Arkansas	GR-97-272	Return on Equity
Arkansas Eastern Gas Company	02/96	Arkansas Western Gas Company	96-030-U	Capital Structure
British Columbia Utilities Commission				
Corix Utilities, Inc.	07/13	Corix Utilities, Inc.	Generic Cost of Capital Proceeding- Phase II	Return on Equity
Corix Utilities, Inc.	08/12	Corix Utilities, Inc.	Generic Cost of Capital Proceeding – Phase I	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/12	San Gabriel Valley Water Company	12-05-002	Return on Equity
San Jose Water Company	05/09	San Jose Water Company	U-168-W	Return on Equity
San Jose Water Company	05/11	San Jose Water Company	U-168-W	Return on Equity
Thames RWE re: California-American Water Co.	05/02	Thames RWE re: California-American Water Co.	02-01-036	Return on Equity
Connecticut Department of Public Utility Control				
Aquarion Water Co. of Connecticut	03/13	Aquarion Water Co. of Connecticut	13-02-30	Return on Equity
Connecticut Water Company	01/10	Connecticut Water Company	09-12-11	Return on Equity
Aquarion Water Company	03/10	Aquarion Water Company	10-02-13	Return on Equity

United Water Connecticut	09/10	United Water Connecticut	10-09-08	Fair Rate of Return
United Water Connecticut	05/07	United Water Connecticut	07-05-44	Fair Rate of Return
Delaware Public Service Commission				
SUEZ Water Delaware Inc.	02/16	SUEZ Water Delaware Inc.		Fair Rate of Return
Artesian Water Company	04/14	Artesian Water Company	14-132	Fair Rate of Return
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	13-466	Return on Equity
Tidewater Utilities, Inc.	09/11	Tidewater Utilities, Inc.	11-397	Fair Rate of Return
Artesian Water Company	04/11	Artesian Water Company	11-207	Fair Rate of Return
United Water Delaware, Inc.	12/10	United Water Delaware, Inc.	10-421	Fair Rate of Return
United Water Delaware, Inc.	02/09	United Water Delaware, Inc.	09-60	Fair Rate of Return
Tidewater Utilities, Inc.	01/09	Tidewater Utilities, Inc.	09-29	Fair Rate of Return
Artesian Water Company	04/08	Artesian Water Company	14-132	Fair Rate of Return
Sussex Shores Water Company	10/07	Sussex Shores Water Company	07-278	Fair Rate of Return
United Water Delaware, Inc.	05/06	United Water Delaware, Inc.	06-174	Fair Rate of Return
Tidewater Utilities, Inc.	04/06	Tidewater Utilities, Inc.	06-145	Fair Rate of Return
Tidewater Utilities, Inc.	04/04	Tidewater Utilities, Inc.	04-152	Fair Rate of Return
Tidewater Utilities, Inc.	01/02	Tidewater Utilities, Inc.	02-28	Fair Rate of Return
Sussex Shores Water Company	11/99	Sussex Shores Water Company	99-576	Fair Rate of Return
Tidewater Utilities, Inc.	9/99	Tidewater Utilities, Inc.	99-446	Fair Rate of Return
Long Neck Water Company	01/99	Long Neck Water Company	99-31	Overall Rate of Return
United Water Delaware, Inc.	03/98	United Water Delaware	98-98	Return on Equity
United Water Delaware, Inc.	08/96	United Water Delaware, Inc.	96-164	Capital Structure and Fixed Capital Cost Rates
Florida Public Service Commission				
Utilities Inc.	08/08	Utilities Inc.	080006-WS	Fair Rate of Return
Utilities, Inc. of Florida	06/03	Utilities, Inc. of Florida	020071-WS	Fair Rate of Return
Hawaiian Public Utilities Commission				
GTE Hawaiian Telephone	10/96	GTE Hawaiian Telephone	95-0054	Common Equity Cost, Capital Structure and Storm Damage Cost Recovery
GTE Hawaiian Telephone	06/96	GTE Hawaiian Telephone	95-0051/94-0298	Self-Insurance Property Damage Reserve-Ratepayer Responsibility
Idaho Public Utility Commission				
United Water Idaho, Inc.	05/15	United Water Idaho, Inc.	UWI-W-15-01	State Property Tax Study

United Water Idaho, Inc.	08/11	United Water Idaho, Inc.	UWI-W-11-02	Fair Rate of Return
United Water Idaho, Inc.	11/04	United Water Idaho, Inc.	UWI-W-04-04	Fair Rate of Return
Illinois Commerce Commission				
Illinois-American Water Company	10/11	Illinois-American Water Company	11-0767	Return on Equity
Apple Canyon Utility Co. / Lake Wildwood Utilities Corp.	04/10	Apple Canyon Utility Co. / Lake Wildwood Utilities Corp.	09-0548/0549	Fair Rate of Return
Illinois American Water Company	05/09	Illinois American Water Company	09-0319	Return on Equity
Illinois-American Water Company	08/07	Illinois-American Water Company	07-0507	Return on Equity
Aqua Illinois, Inc.	02/06	Aqua Illinois, Inc. - Kankakee Water Division	06-0285	Return on Equity
Aqua Illinois	12/04	Aqua Illinois - Woodhaven Water & Sewer Divisions	05-0071	Return on Equity
Aqua Illinois	12/04	Aqua Illinois - Oak Run Water & Sewer Divisions	05-0072	Return on Equity
United Water Idaho, Inc.	11/04	United Water Idaho, Inc.	UWI-W-04-04	Fair Rate of Return
Aqua Illinois	05/04	Aqua Illinois - Vermillion Water Division	04-0442	Return on Equity
Aqua Illinois (formerly Consumers Ill. Water Co.)	05/03	Aqua Illinois (formerly Consumers Ill. Water Co.)	03-0403	Fair Rate of Return
Aqua Illinois (formerly Consumers Ill. Water Co.)	04/00	Aqua Illinois (formerly Consumers Ill. Water Co.)	00-0337, 00-0338, 00-0339	Return on Equity
Indiana Utility Regulatory Commission				
Indiana-American Water Company	01/14	Indiana-American Water Company	44450	Return on Equity
Pioneer Water LLC	10/13	Pioneer Water LLC	4434	Return on Equity
Utility Center, Inc.	03/10	Utility Center, Inc.	43874	Fair Rate of Return
Twin Lakes Utilities, Inc.	11/06	Twin Lakes Utilities, Inc.	43128	Fair Rate of Return
Utility Center, Inc.	08/07	Utility Center, Inc.	43331	Fair Rate of Return
Twin Lakes Utilities, Inc.	09/03	Twin Lakes Utilities, Inc.	42488	Fair Rate of Return
United Water West Lafayette, Inc.	01/97	United Water West Lafayette, Inc.	41046	Return on Equity
United Water Indiana, Inc.	01/97	United Water Indiana, Inc.	41047	Return on Equity
Iowa Utilities Board				
Iowa-American Water Company	04/11	Iowa-American Water Company	RPU-2011-0001	Return on Equity
Iowa-American Water Company	04/09	Iowa-American Water Company	RPU-2009-0004	Return on Equity
Iowa-American Water Company	08/07	Iowa-American Water Company	RPU-2007-0003	Return on Equity
Kentucky Public Service Commission				
Water Service Corp. of Kentucky	01/09	Water Service Corp. of Kentucky	2008-00563	Fair Rate of Return

Water Service Corp. of Kentucky	08/05	Water Service Corp. of Kentucky	2005-00325	Fair Rate of Return
Louisiana Public Service Commission				
Louisiana Water Service, Inc.	03/08	Louisiana Water Service, Inc.	U-30553	Fair Rate of Return
Maine Public Service Commission				
Maine Water Company	12/13	Maine Water Company – Camden & Rockland Division	2013-00362	Return on Equity
Consumers Maine Water Company	05/00	Consumers Maine Water Company	2000-96 & 2000-175	Return on Equity
Maryland Public Service Commission				
Greenridge Utilities, Inc.	05/03	Greenridge Utilities, Inc.	8962	Fair Rate of Return
Michigan Public Service Commission				
Alpena Power Company	05/09	Alpena Power Company	U-15935	Fair Rate of Return
Alpena Power Company	04/07	Alpena Power Company	U-15250	Fair Rate of Return
Alpena Power Company	07/99	Alpena Power Company	U-12000	Return on Equity
Missouri Public Service Commission				
Missouri Gas Energy	09/13	Missouri Gas Energy	GR-2014-0007	Return on Equity
Missouri-American Water Company	06/11	Missouri-American Water Company	WR-2011-0337 / SR-2011-0338	Fair Rate of Return
Missouri-American Water Company	10/09	Missouri-American Water Company	WR-2010-0131	Return on Equity
Missouri American Water Company	03/08	Missouri American Water Company	WR-2008-0311 / SR-2008-0312	Return on Equity
Missouri American Water Company	12/06	Missouri American Water Company	WR-2007-0216 / WR-2007-0217	Return on Equity
Missouri-American Water Company	05/03	Missouri-American Water Company	WR-2003-0500 & WC-2004-0168	Fair Rate of Return
Arkansas Western Gas Company	02/97	ANG Division – Missouri	GR-97-272	Capital Structure
New Hampshire Public Utilities Commission				
Aquarion Water Co. of New Hampshire, Inc.	03/13	Aquarion Water Co. of New Hampshire, Inc.	DW 12-085	Return on Equity
New Jersey Board of Public Utilities				
Aqua New Jersey, Inc.	1/16	Aqua New Jersey, Inc.		Return on Equity
United Water New Jersey, Inc.	10/15	United Water New Jersey, Inc.	WR-15101177	Return on Equity
United Water Toms River, Inc.	02/15	United Water Toms River, Inc.	W-01303A-14-0010	Return on Equity
Atlantic City Sewerage Company	10/14	Atlantic City Sewerage Company	WR-14101263	Return on Equity
Aqua New Jersey, Inc.	01/14	Aqua New Jersey, Inc.	WR-14010019	Fair Rate of Return
Middlesex Water Company	11/13	Middlesex Water Company	WR-13111059	Return on Equity
United Water New Jersey, Inc.	03/13	United Water New Jersey, Inc.	WR-13030210	Fair Rate of Return

Jersey Central Power & Light Company	11/12	Jersey Central Power & Light Company	ER-12111052	Return on Equity
United Water Toms River, Inc.	09/12	United Water Toms River, Inc.	WR-12090830	Fair Rate of Return
Pinelands Water Company	08/12	Pinelands Water Company	WR-12080735	Return on Equity
Pinelands Wastewater Company	08/12	Pinelands Wastewater Company	WR-12080734	Return on Equity
Middlesex Water Company	01/12	Middlesex Water Company	WR-12010027 / PUC 1653-2012	Fair Rate of Return
Aqua New Jersey, Inc.	12/11	Aqua New Jersey, Inc.	WR 11120859	Fair Rate of Return
The New Jersey Utilities Association	10/11	The New Jersey Utilities Association	PUC 07146-09 (OAL) / WO-090148 (BPU)	Return on Equity
United Water New Jersey, Inc.	07/11	United Water New Jersey, Inc.	WR-11070428	Fair Rate of Return
The Atlantic City Sewerage Company	04/11	The Atlantic City Sewerage Company	WR-11040247	Fair Rate of Return
United Water Great Gorge, Inc./United Water Vernon Sewerage, Inc.	10/10	United Water Great Gorge, Inc./United Water Vernon Sewerage, Inc.	WR-10100785	Fair Rate of Return
United Water New Jersey, Inc.	12/09	United Water New Jersey, Inc.	WR-09120987	Fair Rate of Return
Aqua New Jersey, Inc.	12/09	Aqua New Jersey, Inc.	WR-09121005	Fair Rate of Return
The Atlantic City Sewerage Company	11/09	The Atlantic City Sewerage Company	WR-09110940	Fair Rate of Return
United Water Toms River, Inc.	11/09	United Water Toms River, Inc.	WR-09110934	Fair Rate of Return
Middlesex Water Company	08/09	Middlesex Water Company	WR-0908066	Fair Rate of Return
United Water New Jersey, Inc.	09/08	United Water New Jersey, Inc.	WR-08090710	Fair Rate of Return
United Water West Milford, Inc.	09/08	United Water West Milford, Inc.	WR-08100928	Fair Rate of Return
United Water Arlington Hills, Inc.	09/08	United Water Arlington Hills, Inc.	WR-08100929	Fair Rate of Return
Applied Wastewater Management	08/08	Applied Wastewater Management	WR-08080550	Fair Rate of Return
Middlesex Water Company	04/08	Pinelands Water Company	WR-08040282	Return on Equity
United Water Toms River, Inc.	03/08	United Water Toms River, Inc.	R-WR-08030139	Fair Rate of Return
Aqua New Jersey, Inc.	12/07	Aqua New Jersey, Inc.	WR-07120955	Fair Rate of Return
The Atlantic City Sewerage Company	11/07	The Atlantic City Sewerage Company	WR-0007110866	Fair Rate of Return
Middlesex Water Company	04/07	Middlesex Water Company	PUCRL 05663-2007N	Fair Rate of Return
United Water New Jersey, Inc.	02/07	United Water New Jersey, Inc.	WR-07020135	Fair Rate of Return
Aqua New Jersey, Inc.	12/05	Aqua New Jersey, Inc.	WR-05121022	Fair Rate of Return
Pinelands Water Company	08/05	Pinelands Water Company	WR-05080681	Return on Equity
Pinelands Wastewater Company	08/05	Pinelands Wastewater Company	WR-05080680	Return on Equity
Middlesex Water Company	05/05	Middlesex Water Company	WR-05050451	Fair Rate of Return

Pinelands Wastewater Company	12/03	Pinelands Wastewater Company	WR-031201017	Return on Equity
Pinelands Water Company	12/03	Pinelands Water Company	WR-031201016	Return on Equity
Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	12/03	Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	WR-03120974	Return on Equity
Middlesex Water Company	11/03	Middlesex Water Company	WR-03110900	Fair Rate of Return
Mount Holly Water Company	07/03	Mount Holly Water Company	WR-03070509 & OAL PUCRL 07280-2003N	Fair Rate of Return
Elizabethtown Water Company	07/03	Elizabethtown Water Company	WR-03070510 & OAL PUCRL 07281-2003N	Return on Equity
New Jersey-American Water Company	04/03	New Jersey-American Water Company	WR-03070511 & OAL PUCRL 07279-2003N	Fair Rate of Return
Thames RWE re: New Jersey-American Water Co.	08/02	Thames RWE re: New Jersey-American Water Co.	WM-01120833	Return on Equity
Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	03/02	Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	WR-02030133	Return on Equity
Elizabethtown Water Company	04/01	Elizabethtown Water Company	WR-01040205	Overall Fair Rate of Return
Middlesex Water Company	06/00	Middlesex Water Company	WR-00060362	Fair Rate of Return
Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	03/00	Aqua New Jersey, Inc. (formerly Consumers New Jersey Water Co.)	WR-00030174 & OAL PUCRS04524-00S	Return on Equity
Middlesex Water Company	09/98	Middlesex Water Company	98-090795	Fair Rate of Return
Middlesex Water Company	11/96	Middlesex Water Company	96-110818	Return on Equity
New York State Public Service Commission				
SUEZ New York Inc.	2/16	SUEZ New York Inc.	16-W-0130	Fair Rate of Return
United Water New Rochelle, Inc. / United Water West Chester, Inc.	11/13	United Water New Rochelle, Inc. / United Water West Chester, Inc.	13-W-0539/13-W-564	Return on Equity
United Water New York, Inc.	07/13	United Water New York, Inc.	13-W-0295	Fair Rate of Return
Long Island American Water Company d/b/a Long Island American Water for Water Service	05/11	Long Island American Water Company	11-W-0200	Return on Equity
United Water Owego-Nichols, Inc.	02/11	United Water Owego-Nichols, Inc.	11-W-0082	Fair Rate of Return
United Water Westchester, Inc.	11/09	United Water Westchester, Inc.	09-W-0828	Fair Rate of Return
United Water New Rochelle Inc.	11/09	United Water New Rochelle Inc.	09-W-0824	Fair Rate of Return
United Water New York, Inc.	09/09	United Water New York, Inc.	09-W-0731	Fair Rate of Return
United Water Owego/Nichols, Inc.	05/07	United Water Owego/Nichols, Inc.	07-W-0639 / 07-W0872	Fair Rate of Return
United Water New York, Inc. / South County	01/06	United Water New York, Inc.	Cases 06-W-0131 and 06-W-0244	Fair Rate of Return
United Water New Rochelle, Inc.	09/04	United Water New Rochelle, Inc.	04-W-1221	Fair Rate of Return

North Carolina Utility Commission				
Carolina Water Service of North Carolina	08/15	Carolina Water Company of North Carolina	W-354, Sub 344	Return on Equity
Aqua North Carolina, Inc.	12/13	Aqua North Carolina, Inc.	W-218, Sub 363	Fair Rate of Return
Carolina Water Service, Inc. of NC.	10/13	Carolina Water Service, Inc. of NC.	W-354 Sub 336	Fair Rate of Return
Pluris, LLC	08/12	Pluris, LLC	W-1282, Sub 8	Return on Equity
Aqua North Carolina, Inc.	05/11	Aqua North Carolina, Inc.	W-218, Sub 319	Fair Rate of Return
Carolina Water Service, Inc. of NC	10/10	Carolina Water Service, Inc. of NC	W-354. Sub 324	Fair Rate of Return
Carolina Water Service, Inc. of NC	10/10	Carolina Water Service, Inc. of NC - Ops. in Currituck Co.	W-354. Sub 327	Fair Rate of Return
Transylvania Utilities, Inc.	05/06	Transylvania Utilities, Inc.	W-1012, Sub 7	Fair Rate of Return
Carolina Pines Utilities, Inc.	04/04	Carolina Pines Utilities, Inc.	W-1151	Return on Equity
Transylvania Utilities, Inc.	04/04	Transylvania Utilities, Inc.	W-1012, Sub 5	Return on Equity
Nero Utilities, Inc.	04/04	Nero Utilities, Inc.	W-1152	Return on Equity
Pennsylvania Public Utility Commission				
United Water Pennsylvania Inc.	01/15	United Water Pennsylvania Inc.	R-2015-2462523	Return on Equity
Penn Estates Utilities, Inc.	12/11	Penn Estates Utilities, Inc.	R-2011-2255159	Return on Equity
United Water Pennsylvania, Inc.	05/11	United Water Pennsylvania, Inc.	R-2011-2232985	Fair Rate of Return
United Water Pennsylvania, Inc.	09/09	United Water Pennsylvania, Inc.	R-2009-2122887	Fair Rate of Return
Penn Estates Utilities, Inc. (Water) / (Sewer)	09/09	Penn Estates Utilities, Inc. (Water) / (Sewer)	R-2009-2117532 / R-2009-2117400	Fair Rate of Return
Utilities, Inc. - Westgate	09/09	Utilities, Inc. - Westgate	R-2009-2117389	Fair Rate of Return
Utilities, Inc. of Pennsylvania	09/09	Utilities, Inc. of Pennsylvania	R-2009-2117402	Fair Rate of Return
Trigen-Philadelphia Energy Corp.	06/09	Trigen-Philadelphia Energy Corp.	R-2009-2111011	Fair Rate of Return
The Columbia Water Company	12/08	The Columbia Water Company	R-2008-2045157	Return on Equity
The Newtown Artesian Water Company	11/08	The Newtown Artesian Water Company	R-2008-2042293	Fair Rate of Return
NRG Energy Center Harrisburg	03/08	NRG Energy Center Harrisburg	R-2008-2028395	Fair Rate of Return
Total Environmental Solutions, Inc. - Treasure Lake Water Division	02/08	Total Environmental Solutions, Inc. - Treasure Lake Water Division	R-00072493	Fair Rate of Return
Total Environmental Solutions, Inc. - Treasure Lake Sewer Division	02/08	Total Environmental Solutions, Inc. - Treasure Lake Sewer Division	R-00072495	Fair Rate of Return
Emporium Water Company	06/06	Emporium Water Company	R-00061297	Fair Rate of Return
NRG Energy Center Pittsburgh	06/06	NRG Energy Center Pittsburgh	R-00061435	Fair Rate of Return
City of DuBois, PA	04/06	City of DuBois, PA	R-00050671	Fair Rate of Return
United Water Pennsylvania, Inc.	01/06	United Water Pennsylvania, Inc.	R-00051186	Fair Rate of Return

Valley Energy, Inc.	10/04	Valley Energy, Inc.	R-00049345	Fair Rate of Return
Borough of Hanover	08/02	Borough of Hanover	R-00027522	Fair Rate of Return
Audubon Water Company	04/02	Audubon Water Company	R-00027104	Fair Rate of Return
Wellsboro Electric Company	10/01	Wellsboro Electric Company	R-00016356	Fair Rate of Return
Emporium Water Company	09/00	Emporium Water Company	R-00005050	Fair Rate of Return
Penn Estates Utilities, Inc.	01/00	Penn Estates Utilities, Inc.	R-00005031 & R-00005032	Fair Rate of Return
Pittsburgh Thermal, L.P.	11/99	Pittsburgh Thermal, L.P.	R-00994641	Fair Rate of Return
PG Energy	03/98	PG Energy	R-009880	Capital Structure and Embedded Fixed Capital Cost Rates
Western Utilities, Inc.	08/97	Western Utilities, Inc.	R-00963856	Fair Rate of Return
PG Energy	05/96	PG Energy	R-0096312	Capital Structure and Embedded Fixed Capital Cost Rates
Public Service Commission of Nevada				
Utilities Inc. of Central Nevada	06/15	Utilities Inc. of Central Nevada	15-06063	Fair Rate of Return
Utilities Inc. of Central Nevada	12/09	Utilities Inc. of Central Nevada	09-12017	Fair Rate of Return
Utilities Inc., of Nevada	06/09	Utilities Inc., of Nevada	09-06037	Fair Rate of Return
Spring Creek Utilities, Inc.	06/08	Spring Creek Utilities, Inc.	08-06036	Fair Rate of Return
Utilities, Inc. of Central Nevada	12/06	Utilities, Inc. of Central Nevada	06-12023	Fair Rate of Return
Spring Creek Utilities, Inc.	04/06	Spring Creek Utilities, Inc.	06-01002	Fair Rate of Return
Public Service Commission of South Carolina				
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	2013-199-WS	Capital Structure
Utilities Services of South Carolina	09/13	Utilities Services of South Carolina	2013-201-WS	Capital Structure
Tega Cay Water Services Inc.	12/12	Tega Cay Water Services Inc.	2012-177-WS	Fair Rate of Return
Carolina Water Service, Inc.	08/11	Carolina Water Service, Inc.	2011-47-WS	Fair Rate of Return
Tega Cay Water Service, Inc.	04/10	Tega Cay Water Service, Inc.	2009-473-WS	Fair Rate of Return
United Utility Companies, Inc.	02/10	United Utility Companies, Inc.	2009-479-W/S	Fair Rate of Return
Utilities Services of South Carolina	11/07	Utilities Services of South Carolina	2007-286-WS	Fair Rate of Return
Southland Utilities, Inc.	09/07	Southland Utilities, Inc.	2007-244-W	Fair Rate of Return
Tega Cay Water Service, Inc.	07/06	Tega Cay Water Service, Inc.	2006-97-WS	Return on Equity
United Utility Companies, Inc.	07/06	United Utility Companies, Inc.	2006-107-W/S	Fair Rate of Return
Carolina Water Service, Inc.	06/06	Carolina Water Service, Inc.	2006-92-W/S	Fair Rate of Return
Utilities Services of South Carolina	11/05	Utilities Services of South Carolina	2005-217-WS	Fair Rate of Return
Carolina Water Service of South	04/05	Carolina Water Service of South	2004-357-W/S	Fair Rate of Return

Carolina		Carolina		
United Utility Companies	01/02	United Utility Companies	2000-0210-W/S	Fair Rate of Return
Carolina Water Service of South Carolina	06/01	Carolina Water Service of South Carolina	2000-0207-W/S	Fair Rate of Return
Public Utility Commission of Ohio				
Aqua Ohio, Inc.	12/13	Aqua Ohio, Inc.	13-2124-WW-AIR	Return on Equity
Ohio American Water Company	8/12	Ohio American Water Company	11-4161-WS-AIR	Fair Rate of Return
Ohio American Water Company	6/09	Ohio American Water Company	09-391-WS-AIR	Fair Rate of Return
Ohio American Water Company	10/06	Ohio American Water Company	06-433-WS-AIR	Fair Rate of Return
Ohio-American Water Company	11/04	Ohio-American Water Company	03-2390-WS-AIR	Return on Equity
Regulatory Commission of Alaska				
Fairbanks Natural Gas, LLC	6/14	Fairbanks Natural Gas, LLC	U-14-102	Fair Rate of Return
Rhode Island Public Utilities Commission				
United Water Rhode Island, Inc.	8/13	United Water Rhode Island, Inc.	4434	Fair Rate of Return
United Water Rhode Island, Inc.	6/11	United Water Rhode Island, Inc.	4255	Fair Rate of Return
Virginia State Corporation Commission				
Aqua Virginia, Inc.	8/14	Aqua Virginia, Inc.	PUE-2014-00045	Return on Equity
Massanutten Public Service Corporation	9/09	Massanutten Public Service Corporation	PUE-2009-00041	Return on Equity
Land'Or Utility Company	12/06	Land'Or Utility Company	PUE-2006-00128	Return on Equity
Massanutten Public Service Corporation	12/06	Massanutten Public Service Corporation	PUE-2006-00126	Return on Equity
Reston Lake Anne Air Conditioning Corp.	5/12	Reston Lake Anne Air Conditioning Corp.	PUE-2011-00130	Return on Equity
Aqua Virginia, Inc.	10/11	Aqua Virginia, Inc. (Monticello)	PUE-2005-00080	Return on Equity
Aqua Virginia, Inc.	10/11	Aqua Virginia, Inc. - Sydnor Hydrodynamics, Inc.	PUE-2011-00099	Return on Equity
United Water Virginia, Inc.	10/97	United Water Virginia, Inc.	PUE-2097-0544	Fair Rate of Return
Washington Utilities & Transportation Commission				
Washington Natural Gas Company	03/95	Washington Natural Gas Company	UG-950278	Capital Structure Ratios - Fixed Capital Cost Rates

Exhibits

MET-ED EXHIBIT PMA-1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

EXHIBIT

TO ACCOMPANY THE

PREPARED DIRECT TESTIMONY

OF

PAULINE M. AHERN, CRRA
PARTNER
SUSSEX ECONOMIC ADVISORS, LLC

CONCERNING

FAIR RATE OF RETURN

METROPOLITAN EDISON COMPANY

DOCKET NO. R-2016-2537349

APRIL 28, 2016

Table of Contents
to Met-Ed Exhibit PMA-1

Metropolitan Edison Company
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2010 - 2014, Inclusive

	2014	2013	2012	2011	2010	5 YEAR AVERAGE
	(MILLIONS OF DOLLARS)					
CAPITALIZATION STATISTICS						
AMOUNT OF CAPITAL EMPLOYED						
TOTAL PERMANENT CAPITAL	$ 1,641.761	$ 1,575.387	$ 1,528.121	$ 1,534.877	$ 1,829.561	
SHORT-TERM DEBT	24.349	92.111	46.250	21.092	124.079	
TOTAL-CAPITAL EMPLOYED	$ 1,666.110	$ 1,667.498	$ 1,574.371	$ 1,555.969	$ 1,953.640	
INDICATED AVERAGE CAPITAL COST RATES (2)						
TOTAL DEBT	5.77 %	6.53 %	6.92 %	6.56 %	4.60 %	
PREFERRED STOCK						
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	51.71 %	49.39 %	47.67 %	47.45 %	40.58 %	47.36 %
PREFERRED STOCK	-	-	-	-	-	-
COMMON EQUITY	48.29	50.61	52.33	52.55	59.42	52.64
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT-TERM	52.42 %	52.19 %	49.20 %	48.16 %	44.36 %	49.27 %
PREFERRED STOCK	-	-	-	-	-	-
COMMON EQUITY	47.58	47.81	50.80	51.84	55.64	50.73
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
DIVIDEND PAYOUT RATIO	- %	- %	- %	36.82 %	51.72 %	17.71 %
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	5.56 %	(2.86) %	5.22 %	7.17 %	5.41 %	4.10 %
TOTAL DEBT / EBITDA (3)	4.67 x	13.46 x	3.73 x	3.46 x	4.36 x	5.94 x
FUNDS FROM OPERATIONS / TOTAL DEBT (4)	4.91 %	(2.70) %	5.38 %	8.87 %	6.45 %	4.58 %
TOTAL DEBT / TOTAL CAPITAL	52.42 %	52.19 %	49.20 %	48.16 %	44.36 %	49.27 %

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt as a percentage of EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization)

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Reports

Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Eighteen Electric Companies
1.	Discounted Cash Flow Model (DCF) (1)	8.80 %
2.	Risk Premium Model (RPM) (2)	10.51
3.	Capital Asset Pricing Model (CAPM) (3)	9.89
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	11.13
5.	Indicated Common Equity Cost Rate before Flotation Costs:	10.15 %
6.	Flotation Cost Adjustment (5)	0.27
7.	Indicated Common Equity Cost Rate before Company-Specific Adjustments:	10.42 %
8.	Business Risk Adjustment (6)	0.10
9.	Credit Risk Adjustment (7)	0.40
10.	Indicated Common Equity Cost Rate after Company-Specific Adjustments:	10.92 %
11.	Recommended Common Equity Cost Rate	10.90 %

Notes:
(1) From Schedule 4.
(2) From page 1 of Schedule 5.
(3) From Schedule 6.
(4) From page 1 of Schedule 8.
(5) From page 1 of Schedule 9.
(6) Business risk adjustment to reflect Metropolitan Edison Company's greater business risk due to its small size relative to the proxy group as detailed in the accompanying direct testimony.
(7) Credit risk adjustment to reflect the riskier credit rating of the Company, Baa1, compared with the average credit rating of the proxy group, A3. The 40 basis point upward adjustment is 1/3 of the recent 120 basis point spread between A and Baa rated public utility bond yields as shown on page 4 of Schedule 5.

PROXY GROUP OF EIGHTEEN ELECTRIC COMPANIES
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2010 - 2014, Inclusive

	2014	2013	2012	2011	2010	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
CAPITALIZATION STATISTICS						
AMOUNT OF CAPITAL EMPLOYED						
TOTAL PERMANENT CAPITAL	$11,892.906	$11,171.607	$10,665.300	$10,565.066	$10,275.765	
SHORT-TERM DEBT	$384.188	$289.523	$304.191	$333.199	$258.972	
TOTAL CAPITAL EMPLOYED	$12,277.094	$11,461.130	$10,969.491	$10,898.265	$10,534.737	
INDICATED AVERAGE CAPITAL COST RATES (2)						
TOTAL DEBT	4.96 %	5.32 %	5.60 %	5.81 %	5.77 %	
PREFERRED STOCK	7.03	7.30	5.33	6.47	5.15	
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	49.54 %	48.73 %	49.12 %	49.65 %	50.05 %	49.42 %
PREFERRED STOCK	0.98	0.99	1.43	1.22	1.37	1.20
COMMON EQUITY	49.48	50.28	49.45	49.13	48.58	49.38
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT-TERM	50.84 %	50.12 %	50.57 %	50.90 %	51.35 %	50.76 %
PREFERRED STOCK	0.95	0.96	1.39	1.19	1.33	1.16
COMMON EQUITY	48.21	48.92	48.04	47.91	47.32	48.08
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
FINANCIAL STATISTICS						
FINANCIAL RATIOS - MARKET BASED						
EARNINGS / PRICE RATIO	6.13 %	5.92 %	5.23 %	7.37 %	7.55 %	6.44 %
MARKET / AVERAGE BOOK RATIO	160.88	145.92	130.21	118.44	104.38	131.97
DIVIDEND YIELD	3.52	3.72	4.11	4.40	4.83	4.12
DIVIDEND PAYOUT RATIO	56.26	64.97	59.40	56.48	68.32	61.09
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	9.92 %	8.93 %	6.83 %	8.62 %	8.72 %	8.60 %
TOTAL DEBT / EBITDA (3)	3.77 X	3.68 X	3.56 X	3.86 X	4.05 X	3.78 X
FUNDS FROM OPERATIONS / TOTAL DEBT (4)	22.93 %	23.92 %	25.03 %	24.25 %	22.98 %	23.82 %
TOTAL DEBT / TOTAL CAPITAL	50.84 %	50.12 %	50.57 %	50.90 %	51.35 %	50.76 %

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: I-Metrix Database
Company SEC Form 10-K

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Eighteen Electric Companies
2010 - 2014, Inclusive

	2014	2013	2012	2011	2010	5 YEAR AVERAGE
ALLETE, Inc.						
Long-Term Debt	46.05 %	45.26 %	45.88 %	44.44 %	44.35 %	45.20 %
Preferred Stock	0.00	0.00	0.00	0.00	0.51	0.10
Common Equity	53.95	54.74	54.12	55.56	55.14	54.70
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Alliant Energy Corp.						
Long-Term Debt	51.02 %	48.94 %	47.37 %	44.56 %	44.87 %	47.35 %
Preferred Stock	2.69	2.93	3.12	3.41	4.08	3.25
Common Equity	46.29	48.13	49.51	52.03	51.05	49.40
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Ameren Corp.						
Long-Term Debt	47.65 %	47.45 %	50.78 %	45.94 %	48.65 %	48.09 %
Preferred Stock	1.09	1.12	1.10	1.00	1.00	1.06
Common Equity	51.26	51.43	48.12	53.06	50.35	50.85
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
American Electric Power Co., Inc.						
Long-Term Debt	52.63 %	53.33 %	53.82 %	52.97 %	55.13 %	53.58 %
Preferred Stock	0.00	0.00	0.00	0.00	0.20	0.04
Common Equity	47.37	46.67	46.18	47.03	44.67	46.38
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Consolidated Edison, Inc.						
Long-Term Debt	49.22 %	47.26 %	47.57 %	47.37 %	48.19 %	47.92 %
Preferred Stock	0.00	0.00	0.00	0.94	0.96	0.38
Common Equity	50.78	52.74	52.43	51.69	50.85	51.70
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Edison International						
Long-Term Debt	45.27 %	47.14 %	45.20 %	55.36 %	51.93 %	48.98 %
Preferred Stock	8.52	7.93	8.61	4.15	3.81	6.60
Common Equity	46.21	44.93	46.19	40.49	44.26	44.42
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Eighteen Electric Companies
2010 - 2014, Inclusive

	2014	2013	2012	2011	2010	5 YEAR AVERAGE
El Paso Electric Company						
Long-Term Debt	53.87 %	51.44 %	54.78 %	52.78 %	51.32 %	52.84 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	46.13	48.56	45.22	47.22	48.68	47.16
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Great Plains Energy, Inc.						
Long-Term Debt	50.09 %	50.02 %	47.19 %	54.16 %	53.96 %	51.08 %
Preferred Stock	0.54	0.56	0.61	0.60	0.62	0.59
Common Equity	49.37	49.42	52.20	45.24	45.42	48.33
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
IDACORP, Inc.						
Long-Term Debt	45.21 %	46.56	46.59	47.25	51.19	47.36 %
Preferred Stock	0.12	0.12	0.13	0.13	0.12	0.12
Common Equity	54.67	53.32	53.28	52.62	48.69	52.52
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
OGE Energy Corp.						
Long-Term Debt	45.92 %	44.14	48.11	49.26	49.61	47.41 %
Preferred Stock	0.00	0.00	5.15	4.61	2.32	2.41
Common Equity	54.08	55.86	46.74	46.13	48.07	50.18
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Otter Tail Corp.						
Long-Term Debt	46.54 %	42.16	43.97	44.73	40.25	43.53 %
Preferred Stock	0.00	0.00	1.62	1.46	1.43	0.90
Common Equity	53.46	57.84	54.41	53.81	58.32	55.57
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
PG&E Corp.						
Long-Term Debt	48.47 %	48.25	49.22	48.89	50.39	49.04 %
Preferred Stock	0.81	0.89	0.96	1.04	1.08	0.96
Common Equity	50.72	50.86	49.82	50.07	48.53	50.00
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Pinnacle West Capital Corp.						
Long-Term Debt	43.04 %	43.46	44.75	46.60	48.68	45.30 %
Preferred Stock	1.91	1.90	1.74	1.48	1.25	1.66
Common Equity	55.05	54.64	53.51	51.92	50.07	53.04
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Eighteen Electric Companies
2010 - 2014, Inclusive

	2014	2013	2012	2011	2010	5 YEAR AVERAGE
PNM Resources, Inc.						
Long-Term Debt	52.39 %	49.93	49.75	50.26	47.46	49.96 %
Preferred Stock	1.95	2.20	2.41	2.48	5.96	3.00
Common Equity	45.66	47.87	47.84	47.26	46.58	47.04
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Portland General Electric Co.						
Long-Term Debt	56.69 %	51.28	48.60	51.01	53.07	52.13 %
Preferred Stock	0.00	0.03	0.06	0.09	0.20	0.08
Common Equity	43.31	48.69	51.34	48.90	46.73	47.79
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
SCANA Corp.						
Long-Term Debt	53.32 %	53.88	55.21	54.47	54.80	54.34 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	46.68	46.12	44.79	45.53	45.20	45.66
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Westar Energy, Inc.						
Long-Term Debt	50.81 %	52.86	51.32	49.71	53.80	51.70 %
Preferred Stock	0.10	0.09	0.24	0.57	0.53	0.31
Common Equity	49.09	47.05	48.44	49.72	45.67	47.99
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Xcel Energy Inc.						
Long-Term Debt	53.51 %	53.92	53.96	53.88	53.23	53.70 %
Preferred Stock	0.00	0.00	0.00	0.00	0.60	0.12
Common Equity	46.49	46.08	46.04	46.12	46.17	46.18
Total Capital	100.00 %	100.00	100.00	100.00	100.00	100.00 %
Proxy Group of Eighteen Electric Companies						
Long-Term Debt	49.54 %	48.73 %	49.12 %	49.65 %	50.05 %	49.42 %
Preferred Stock	0.98	0.99	1.43	1.22	1.37	1.20
Common Equity	49.48	50.28	49.45	49.13	48.58	49.38
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for
the Proxy Group of Eighteen Electric Companies

Proxy Group of Eighteen Electric Companies	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Reuters Mean Consensus Projected Five Year Growth Rate in EPS	[4] Zack's Five Year Projected Growth Rate in EPS	[5] Yahoo! Finance Projected Five Year Growth in EPS	[6] Average Projected Five Year Growth in EPS (3)	[7] Adjusted Dividend Yield (4)	[8] Indicated Common Equity Cost Rate (5)
ALLETE, Inc.	4.12 %	6.50 %	5.00 %	5.00 %	5.00 %	5.38 %	4.23 %	9.61 %
Alliant Energy Corp.	3.85	6.00	5.55	5.40	5.55	5.63	3.96	9.59
Ameren Corp.	3.93	7.00	5.20	6.30	5.20	5.93	4.05	9.98
American Electric Power Co., Inc.	3.93	5.00	4.55	4.70	4.55	4.70	4.02	8.72
Consolidated Edison, Inc.	4.16	3.00	2.94	3.10	2.95	3.02	4.22	7.24
Edison International	3.21	3.50	(2.34)	4.40	NA	3.95	3.27	7.22
El Paso Electric Company	3.07	3.50	NA	6.70	7.00	5.73	3.16	8.89
Great Plains Energy, Inc.	3.90	5.00	5.07	5.80	5.07	5.24	4.00	9.24
IDACORP, Inc.	3.03	1.00	4.00	4.00	4.00	3.25	3.08	6.33
OGE Energy Corp.	4.28	3.00	2.17	5.70	2.17	3.26	4.35	7.61
Otter Tail Corp.	4.64	9.00	NA	NA	6.00	7.50	4.81	12.31
PG&E Corp.	3.44	10.50	5.21	4.50	5.21	6.36	3.55	9.91
Pinnacle West Capital Corp.	3.94	4.00	4.95	4.80	4.95	4.68	4.03	8.71
PNM Resources, Inc.	2.99	9.00	9.30	7.70	9.30	8.83	3.12	11.95
Portland General Electric Co.	3.28	6.00	4.13	4.40	4.13	4.67	3.36	8.03
SCANA Corp.	3.64	4.50	4.45	4.50	4.45	4.48	3.72	8.20
Westar Energy, Inc.	3.46	6.00	3.50	3.60	3.50	4.15	3.53	7.68
Xcel Energy Inc.	3.57	4.50	4.84	5.00	4.84	4.80	3.54	8.34
							Average	8.87 %
							Median	8.72 %
							Average of Mean and Median	8.80 %

NA= Not Available
NMF = Not Meaningful Figure

Notes:

(1) Indicated dividend at 01/29/2016 divided by the average closing price of the last 60 trading days ending 01/29/2016 for each company.

(2) From pages 3 through 20 of this Schedule.

(3) Average of columns 2 through 5 excluding negative growth rates.

(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for ALLETE, Inc., 4.12% x (1+(1/2 x 5.38%)) = 4.23%.

(5) Column 6 + column 7.

Source of Information:

Value Line Investment Survey
www.reuters.com Downloaded on 01/29/2016
www.zacks.com Downloaded on 01/29/2016
www.yahoo.com Downloaded on 01/29/2016

Demonstration of the Inadequacy of a DCF Return Rate Related to Book Value When Market Value is Greater than Book Value

		Based on the Proxy Group of Eighteen Electric Companies	
		Column A	Column B
Line No.		Market Value	Book Value
1.	Per Share	$ 49.11 (1)	$ 28.99 (2)
2.	DCF Cost Rate (3)	8.87%	8.87%
3.	Return in Dollars (4)	$ 4.356	$ 2.571
4.	Dividends (5)	$ 1.856	$ 1.856
5.	Growth in Dollars (6)	$ 2.500	$ 0.715
6.	Return on Market Value (7)	8.87%	5.24%
7.	Rate of Growth on Market Value (8)	5.09%	1.46%

Notes:

(1) Average price of the Electric Proxy Group as shown on page 2 of Schedule 10.
(2) Average book value of the Electric Proxy Group as shown on page 2 of Schedule 10.
(3) Average DCF cost rate from page 1 of this Schedule.
(4) Line 1 x Line 2.
(5) Dividends are based on a 3.78% adjusted dividend yield which is the average adjusted dividend yield of the Electric Proxy Group.

(6) Line 3 - Line 4.
(7) Line 3 / Line 1.
(8) Line 7 / Line 1.

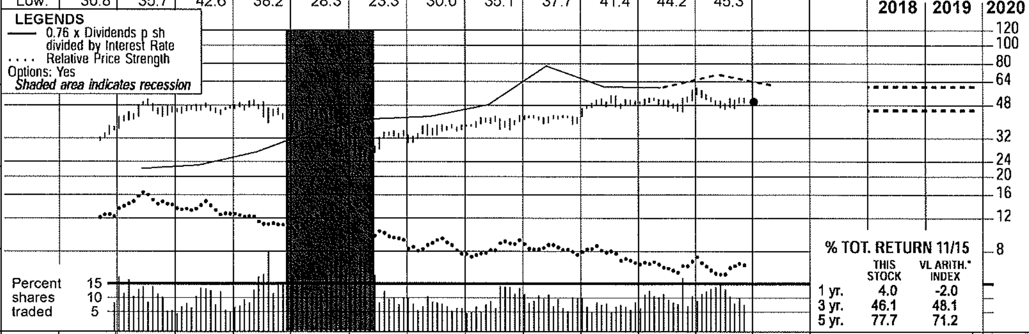
ALLETE NYSE-ALE

RECENT PRICE 50.15 | P/E RATIO 14.2 (Trailing: 15.3; Median: 16.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 4/24/15
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 12/18/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3

Target Price Range
2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	9%
Low	45	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	1	0
to Sell	0	1	2	1	1	1	0	3	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	117	117	90
to Sell	77	79	100
Hld's(000)	33487	35643	35552

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	-2.0
3 yr.	46.1	48.1
5 yr.	77.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	**30.60**	**28.45**	Revenues per sh	**33.50**
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	**6.50**	**6.40**	"Cash Flow" per sh	**7.75**
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	**3.50**	**3.20**	Earnings per sh A	**4.00**
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	**2.02**	**2.08**	Div'd Decl'd per sh B ■ †	**2.30**
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	**5.70**	**4.75**	Cap'l Spending per sh	**5.50**
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	**37.50**	**38.70**	Book Value per sh C	**43.50**
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	**49.00**	**49.25**	Common Shs Outst'g D	**50.00**
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**13.0**
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91			Relative P/E Ratio	**.80**
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%			Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1598.1 mill. **Due in 5 Yrs** $411.9 mill.
LT Debt $1549.0 mill. **LT Interest** $64.4 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill. **Oblig.** $714.5 mill.

Pfd Stock None

Common Stock 48,965,562 shs.

MARKET CAP: $2.5 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	**1500**	**1400**	Revenues ($mill)	**1675**
68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	**165**	**155**	Net Profit ($mill)	**195**
28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	**20.0%**	**20.0%**	Income Tax Rate	**20.0%**
.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	**3.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	**43.5%**	**42.5%**	Long-Term Debt Ratio	**41.0%**
60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	**56.5%**	**57.5%**	Common Equity Ratio	**59.0%**
990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	**3260**	**3330**	Total Capital ($mill)	**3675**
860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	**3675**	**3750**	Net Plant ($mill)	**4075**
8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	**6.0%**	**5.5%**	Return on Total Cap'l	**6.5%**
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	**9.0%**	**8.0%**	Return on Shr. Equity	**9.0%**
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	**9.0%**	**8.0%**	Return on Com Equity E	**9.0%**
5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	**4.0%**	**3.0%**	Retained to Com Eq	**3.5%**
54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	**57%**	**66%**	All Div'ds to Net Prof	**59%**

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	--	5.5%
"Cash Flow"	6.0%	5.5%	6.5%
Earnings	7.0%	1.0%	6.5%
Dividends	NMF	2.0%	3.0%
Book Value	4.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	**394.2**	**1500**
2016	**345**	**340**	**360**	**355**	**1400**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	**.96**	**3.50**
2016	**.90**	**.45**	**1.00**	**.85**	**3.20**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings will almost certainly wind up significantly higher in 2015, thanks to a development fee for the construction of a wind project. The company's ALLETE Clean Energy subsidiary is building a wind project that it is selling to a utility in North Dakota. The company booked a progress payment that boosted profits by $0.25 a share in the third quarter, and the final payment should add another $0.12 a share or so in the December period. Because the project management has been even stronger than expected, and Minnesota Power (ALLETE's main utility subsidiary) has cut expenses through a cost-reduction program, management raised its share-earnings target for the year from $3.20-$3.40 to $3.35-$3.50. We have raised our share-net estimate by $0.20, so it now stands at the upper end of the company's guidance.

We think earnings will decline in 2016. The comparisons will be difficult in the second half of the year because of the boost provided by the aforementioned wind project fees. In addition, activity by Minnesota Power's taconite customers has waned. (Taconite is used in steelmaking.) These large electricity users had been running at full capacity for the past several years, but are now expecting 80% of full-demand levels for the first four months of 2016. The utility might be able to make up for part of the shortfall through additional wholesale power sales. The one positive factor for the year-to-year comparisons is that the company's purchase of U.S. Water, which provides water management services to industrial customers, should be more accretive to income next year once some amortizations cease after the first quarter. Our earnings estimate is within ALLETE's targeted range of $3.10-$3.40 a share.

We think the board of directors will raise the annual dividend by $0.06 a share (3.0%) in the first period of 2016. This has been the pattern in recent years. ALLETE is targeting a payout ratio in a range of 60%-65%.

This stock's dividend yield is slightly above the utility mean. Total return potential to 2018-2020 is only average for the group, however.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

ALLIANT ENERGY NYSE-LNT

RECENT PRICE 60.69 | P/E RATIO 16.3 (Trailing: 16.9 Median: 14.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 8/22/14

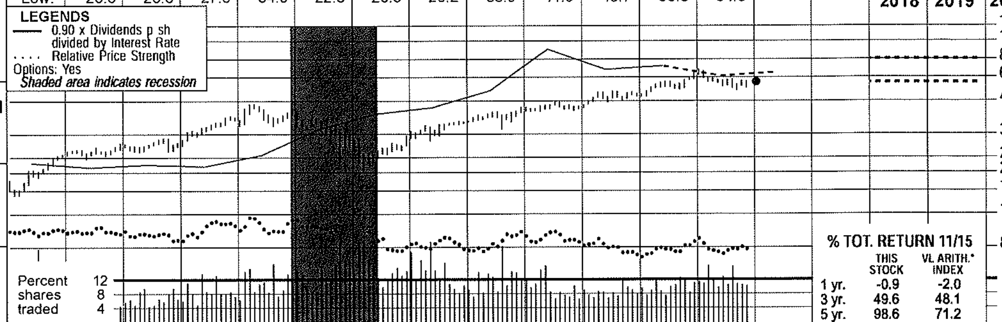
SAFETY 2 Raised 9/28/07

TECHNICAL 4 Raised 12/11/15

BETA .80 (1.00 = Market)

High:	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	47.7	54.2	69.8	70.8
Low:	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9	43.7	50.0	54.3

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+30%)	10%
Low	60	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	192	155	166
to Sell	135	156	142
Hld's(000)	69740	70359	71544

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.9	-2.0
3 yr.	49.6	48.1
5 yr.	98.6	71.2

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.02	28.93	31.15	33.33	31.02	30.81	33.02	27.88	29.54	30.20	**30.10**	**30.85**	Revenues per sh	**34.80**
5.46	4.33	5.12	4.56	4.21	5.21	5.51	5.90	6.68	6.88	**7.10**	**7.50**	"Cash Flow" per sh	**8.20**
2.21	2.06	2.69	2.54	1.89	2.75	2.75	3.05	3.29	3.48	**3.65**	**3.85**	Earnings per sh A	**4.55**
1.05	1.15	1.27	1.40	1.50	1.58	1.70	1.80	1.88	2.04	**2.20**	**2.36**	Div'd Decl'd per sh B ■ †	**2.85**
4.51	3.42	4.91	7.96	10.87	7.82	6.07	10.43	6.63	7.56	**8.75**	**9.00**	Cap'l Spending per sh	**9.80**
20.85	22.83	24.30	25.56	25.07	26.09	27.14	28.25	29.58	31.09	**31.95**	**32.65**	Book Value per sh C	**34.65**
117.04	116.13	110.36	110.45	110.66	110.89	111.02	110.99	110.94	110.94	**113.00**	**113.50**	Common Shs Outst'g D	**115.00**
12.6	16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**15.0**
.67	.91	.80	.81	.93	.80	.91	.92	.86	.88	*estimates*		Relative P/E Ratio	**.95**
3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%			Avg Ann'l Div'd Yield	**4.2%**
3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	**3400**	**3500**	Revenues ($mill)	**4000**
337.8	260.1	320.8	280.0	208.6	303.9	304.4	337.8	382.1	385.5	**410**	**435**	Net Profit ($mill)	**525**
19.0%	43.8%	44.4%	33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	**15.0%**	**15.0%**	Income Tax Rate	**20.0%**
3.0%	3.1%	2.4%	--	--	--	--	--	8.8%	6.5%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	**47.5%**	**47.5%**	Long-Term Debt Ratio	**47.5%**
53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	**49.5%**	**49.5%**	Common Equity Ratio	**49.5%**
4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	**7500**	**7600**	Total Capital ($mill)	**7800**
4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	**7800**	**8000**	Net Plant ($mill)	**9000**
8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.5%**
12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.0%**
13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	**11.5%**	**11.5%**	Return on Com Equity E	**11.5%**
8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	**4.5%**	**4.5%**	Retained to Com Eq	**4.5%**
42%	59%	50%	62%	88%	64%	67%	64%	57%	61%	**60%**	**61%**	All Div'ds to Net Prof	**63%**

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3967.9 mill. **Due in 5 Yrs** $1100.0 mill.
LT Debt $3855.8 mill. **LT Interest** $175.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/14 $1022.9 mill. **Oblig.** $1301.5 mill.
Pfd Stock $200.0 mill. **Pfd Div'd** $10.2 mill.
8,000,000 shs.

Common Stock 113,360,425 shs.

MARKET CAP: $6.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.3	+.1	+.1
Avg. Indust. Use (MWH)	11555	11471	11821
Avg. Indust. Revs. per KWH (¢)	6.42	6.75	6.85
Capacity at Peak (Mw)	5886	5820	5426
Peak Load, Summer (Mw)	5886	5820	5426
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.4
Fixed Charge Cov. (%)	332	295	320

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-1.5%	*4.0%*
"Cash Flow"	4.0%	7.0%	*6.0%*
Earnings	8.0%	6.5%	*6.0%*
Dividends	3.5%	6.5%	*4.5%*
Book Value	3.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	765.7	690.3	887.6	750.9	3094.5
2013	859.6	718.0	866.6	832.6	3276.8
2014	952.8	750.3	843.1	804.1	3350.3
2015	897.4	717.2	898.9	**886.5**	**3400**
2016	**900**	**750**	**950**	**900**	**3500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.58	1.34	.63	3.05
2013	.72	.59	1.43	.55	3.29
2014	.97	.56	1.40	.55	3.48
2015	.87	.60	1.59	**.59**	**3.65**
2016	**.90**	**.65**	**1.70**	**.60**	**3.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.425	.425	.425	.425	1.70
2012	.45	.45	.45	.45	1.80
2013	.47	.47	.47	.47	1.88
2014	.51	.51	.51	.51	2.04
2015	.55	.55	.55	.55	

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 44%; IA, 55%; MN, 1%. Elect. rev.: residential, 39%; commercial, 24%; industrial, 30%; wholesale, 6%; other, 1%. Fuel sources, 2014: coal, 47%; nuclear, 17%; gas, 4%; other, 32%. Fuel costs: 50% of revs. 2014 depreciation rate: 5.5%. Estimated plant age: 12 years. Has 4,200 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy tightened its guidance range for 2015. The company narrowed its consolidated earnings guidance for the current year to $3.50-$3.65 a share, from the prior range of $3.45-$3.75 a share. The slight change in anticipated profitability is likely due to a weaker contribution from the utility's non-regulated parent company, which is expected to add roughly $0.05-$0.10 in share net this year, and from a higher overall tax rate (15%) compared to last year. Despite this, we have raised our 2015 earnings estimate by a nickel, to $3.65 a share, due to better-than-expected third-quarter results and, in our view, a conservative forecast from management.

Meanwhile, the company gave its first targeted outlook for 2016 and updated its capital expenditure plan for the next five years. Alliant initiated guidance for the following year at $3.60 to $3.90 a share. Admittingly, the midpoint of that range falls below our estimate of $3.85 a share. However, we think management is once again acting conservative, thus we have left our full-year estimate intact. In addition, Alliant expects capital expenditures to peak between 2017 and 2018, at $1.25 billion a year, due to the Riverside Energy Center expansion, and then fall to $1 billion annually by 2019.

The company is bolstering its renewable energy portfolio in Iowa. Specifically, management is seeking to expand its solar-producing capacity by 50%. The utility sent several proposals to state regulators for new solar projects and is currently awaiting approval. Moreover, as mentioned in our September report, new rules issued by the EPA are expected to clamp down on harmful emissions over the next few years. And, while this will have an impact on Alliant, we take comfort knowing that management is ahead of the game on transitioning to cleaner energy.

The distribution will likely be raised at the January board meeting. Management is targeting a payout ratio between 60% and 70%, so dividend growth is likely tied to earnings advances henceforth. Consequently, we think a raise of about 6% to 8% is most probable in 2016.

These shares offer investors a secure and growing income stream.

Daniel Henigson *December 18, 2015*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢); '12, (16¢). Next egs. rpt. due early February. **(B)** Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. deferred chgs. In '14: $90.0 mill., $0.77/sh. **(D)** In mill. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '14: 10.9%; in WI in '14 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

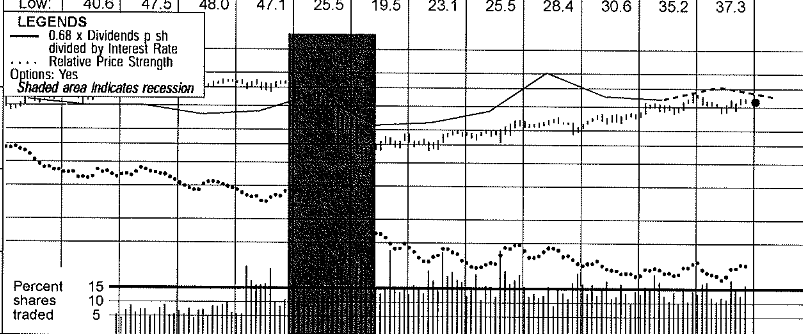
AMEREN NYSE-AEE

RECENT PRICE 42.74 | P/E RATIO 16.4 (Trailing: 17.4 Median: 15.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 11/20/15
SAFETY 2 Raised 6/20/14
TECHNICAL 1 Raised 12/11/15
BETA .75 (1.00 = Market)

High:	50.4	56.8	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	
Low:	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	8%
Low	35	(-20%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	174	175	189
to Sell	212	202	190
Hld's(000)	160314	158124	159419

Percent shares traded 15 10 5

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.7	-2.0
3 yr.	66.4	48.1
5 yr.	92.4	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	**25.35**	**26.15**	Revenues per sh	**30.00**
5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	**6.05**	**6.55**	"Cash Flow" per sh	**8.00**
2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	**2.45**	**2.75**	Earnings per sh A	**3.50**
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	**1.66**	**1.72**	Div'd Decl'd per sh B ■	**1.95**
4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	**8.10**	**7.15**	Cap'l Spending per sh	**7.25**
22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	**28.70**	**29.75**	Book Value per sh C	**34.00**
137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	**242.63**	**242.63**	Common Shs Outst'g D	**242.63**
13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	**12.5**
.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	*Value Line*		Relative P/E Ratio	**.80**
6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	*estimates*		Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 9/30/15
Total Debt $7159 mill. **Due in 5 Yrs** $3400 mill.
LT Debt $5981 mill. **LT Interest** $315 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $13 mill.
Pension Assets-12/14 $3794 mill.
Oblig. $4410 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. as of 10/30/15
MARKET CAP: $10.4 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	**6150**	**6350**	Revenues ($mill)	**7250**
628.0	547.0	629.0	615.0	624.0	669.0	602.0	589.0	518.0	593.0	**605**	**675**	Net Profit ($mill)	**860**
35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	**38.0%**	**38.5%**	Income Tax Rate	**38.5%**
2.9%	.7%	.8%	4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	**4.0%**	**4.0%**	AFUDC % to Net Profit	**3.0%**
44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	**49.5%**	**47.5%**	Long-Term Debt Ratio	**46.5%**
53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	**49.5%**	**51.5%**	Common Equity Ratio	**52.5%**
11932	12063	12654	13712	15991	15185	14738	13384	12190	12975	**14025**	**13975**	Total Capital ($mill)	**15700**
13572	14286	15069	16567	17610	17853	18127	16096	16205	17424	**18525**	**19325**	Net Plant ($mill)	**21400**
6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	**8.5%**	**9.0%**	Return on Shr. Equity	**10.0%**
9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	**8.5%**	**9.5%**	Return on Com Equity E	**10.5%**
1.7%	.2%	1.3%	1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	**3.0%**	**3.5%**	Retained to Com Eq	**4.5%**
83%	97%	86%	88%	56%	56%	63%	66%	76%	67%	**67%**	**62%**	All Div'ds to Net Prof	**56%**

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.7	-.5	-.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.80	5.41	5.46
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	291	289	355

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	-5.5%	2.5%
"Cash Flow"	--	-2.5%	6.0%
Earnings	-2.0%	-4.5%	7.0%
Dividends	-4.5%	-6.0%	3.5%
Book Value	--	-3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1658	1660	2001	1509	6828.0
2013	1475	1403	1638	1322	5838.0
2014	1594	1419	1670	1370	6053.0
2015	1556	1401	1833	**1360**	**6150**
2016	**1600**	**1500**	**1850**	**1400**	**6350**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.11	.87	1.54	.11	2.41
2013	.22	.44	1.25	.19	2.10
2014	.40	.62	1.20	.19	2.40
2015	.45	.40	1.41	**.19**	**2.45**
2016	**.40**	**.60**	**1.45**	**.30**	**2.75**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.385	.385	.385	.40	1.56
2012	.40	.40	.40	.40	1.60
2013	.40	.40	.40	.40	1.60
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued power-generation operation in '13. Electric rev. breakdown: residential, 45%; commercial, 33%; industrial, 12%; other, 10%. Generating sources: coal, 74%; nuclear, 21%; hydro, 2%; purchased, 3%. Fuel costs: 31% of revs. '14 reported deprec. rates: 3%-4%. Has 8,500 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has received rulings on its regulatory matters in Illinois. Details weren't available as this report went to press, but we think the outcome wasn't far from what the utility sought. Ameren requested a $109 million increase under the state's formula rate plan for electric companies, and a $45 million gas rate hike, based on a return of 9.6% on a common-equity ratio of 50%. In each case, the commission's staff and an administrative law judge are recommending raises that are very close to what Ameren filed for. Each order will go into effect in January. This rate relief will contribute to the profit growth we expect next year.

We now think earnings will wind up slightly higher in 2015, despite a charge Ameren took in the June quarter. The write-off of costs incurred toward a construction and operating license for a second unit at the Calloway nuclear plant, which won't be built, lowered profits by $0.18 a share. The company is excluding this item from its earnings guidance of $2.55-$2.65 a share. That's why our estimate of $2.45, which we raised by a nickel, is below this range. Ameren is benefiting from capital spending on electric transmission (see below).

Electric transmission is a key area of investment for Ameren. The company expects to spend $2.3 billion on federally regulated transmission projects for the five-year period through 2019. This is one factor behind the strong profit growth we expect in 2016 and beyond. Investors should note, however, that transmission companies in the region are facing two complaints with the Federal Energy Regulatory Commission that allowed return on equity are too high. These won't be resolved until 2016 and 2017.

The board of directors raised the dividend in the fourth quarter. The increase was $0.015 (3.7%) a share quarterly. This is slightly more than we had estimated.

The dividend yield and 3- to 5-year total return potential of Ameren stock are roughly equivalent to the averages for the electric utility industry. Like many utility issues, the stock is trading near the midpoint of our 2018-2020 Target Price Range.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '14 EPS don't add due to rounding. Next egs. report due mid-Feb. (B) Div'ds historic. paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $8.21/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '15: 9.53% elec., in '11: none spec. gas; in IL in '14: 8.7% elec., 9.06% gas; earned on avg. com. eq., '14: 8.9%. Reg. Clim.: MO, Avg.; IL, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	15
Earnings Predictability	85

AMERICAN ELEC. PWR. NYSE-AEP

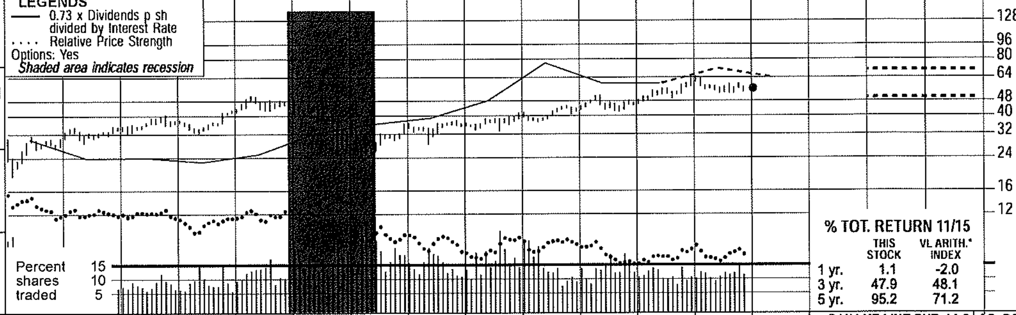
RECENT PRICE 55.88 | P/E RATIO 15.8 (Trailing: 15.4 Median: 13.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 6/12/15
SAFETY 2 Raised 9/19/14
TECHNICAL 2 Raised 12/18/15
BETA .70 (1.00 = Market)

High: 35.5 40.8 43.1 51.2 49.1 36.5 37.9 41.7 45.4 51.6 63.2 65.4
Low: 28.5 32.3 32.3 41.7 25.5 24.0 28.2 33.1 37.0 41.8 45.8 52.3

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	10%
Low	50	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	10	0	0	0	0
to Sell	0	1	0	0	4	0	0	3	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	338	327	328
to Sell	368	336	317
Hld's(000)	324222	328262	332965

Percent shares traded 15 10 5

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	-2.0
3 yr.	47.9	48.1
5 yr.	95.2	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	*33.95*	*34.40*	Revenues per sh	*37.75*
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	*8.10*	*8.35*	"Cash Flow" per sh	*9.25*
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	*3.70*	*3.70*	Earnings per sh A	*4.25*
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	*2.15*	*2.27*	Div'd Decl'd per sh B ■	*2.65*
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	*9.75*	*10.45*	Cap'l Spending per sh	*8.50*
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	*36.00*	*37.50*	Book Value per sh C	*42.25*
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	*492.00*	*494.00*	Common Shs Outst'g D	*500.00*
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	*Value Line*		Relative P/E Ratio	*.90*
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $20208 mill. Due in 5 Yrs $9052 mill.
LT Debt $17600 mill. LT Interest $792 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill. Oblig. $5225 mill.
Pfd Stock None

Common Stock 490,817,402 shs. as of 10/22/15
MARKET CAP: $27 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	*16700*	*17000*	Revenues ($mill)	*18850*
1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	*1730*	*1745*	Net Profit ($mill)	*2020*
29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.0%*
44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	*50.0%*	*50.5%*	Common Equity Ratio	*51.0%*
20222	21902	24342	26290	28958	29184	29747	30823	32913	33001	*35400*	*36675*	Total Capital ($mill)	*41500*
24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	*46725*	*49600*	Net Plant ($mill)	*54900*
6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	*10.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	*10.5%*	*10.0%*	Return on Com Equity E	*10.0%*
5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	*4.5%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	53%	55%	55%	56%	66%	60%	63%	62%	61%	*61%*	*64%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.5%	--	2.5%
"Cash Flow"	1.5%	1.5%	4.5%
Earnings	1.5%	1.5%	5.0%
Dividends	.5%	4.0%	5.0%
Book Value	4.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4568	3839	4432	*3861*	*16700*
2016	*4450*	*4050*	*4450*	*4050*	*17000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.28	.88	1.06	*.48*	*3.70*
2016	*1.15*	*.85*	*1.20*	*.50*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric rev. breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 36% of revs. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is trying to reach a settlement in Ohio about its proposed purchased-power agreement. In recent years, the company has been moving away from the nonregulated side of the business in favor of its regulated utilities. Low capacity prices have hurt the profitability of AEP's nonregulated generating assets. So, the company proposed a purchased-power agreement between some nonregulated generating assets and its utilities in Ohio. The outcome of this matter might well be determined in early 2016. A sale or spinoff of these assets is possible if a settlement is not reached. Note that another company in the state reached a settlement with the commission's staff on a similar proposal, but still faces some opposition—as does AEP.

We have raised our 2015 and 2016 earnings estimates slightly. We lifted our 2015 estimate by $0.10 a share and our 2016 forecast by $0.05 a share. Our $3.70-a-share estimate each year is within AEP's guidance of $3.67-$3.77 and $3.60-$3.80, respectively. The utilities are generally faring well, and are benefiting from rate relief. Increased investment in electric transmission is another plus for AEP. This is outweighing the aforementioned disadvantage of low capacity prices.

Public Service of Oklahoma has a rate case pending. The utility filed for a tariff hike of $172 million, based on a return of 10.5% on a common-equity ratio of 48%. New rates should take effect at the start of 2016.

The board of directors raised the dividend in the fourth quarter. The increase was $0.03 a share (5.7%) quarterly. AEP is targeting a payout ratio of 60%-70%.

The company sold its commercial barge operation. This business earned $0.03 a share in the first three quarters of 2015, which is now included in discontinued operations. The sale raised $400 million in cash, which AEP will use for its regulated utilities. The company hasn't stated whether it will book a gain or loss on the sale.

This stock's valuation is about average for a utility. The dividend yield and total return potential to 2018-2020 are close to the industry averages.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 4¢. '14 EPS don't add due to rounding. Next egs. report due late Jan. (B) Div'ds historic. paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $17.67/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '14: 9.9%. Reg. Clim.: Avg.

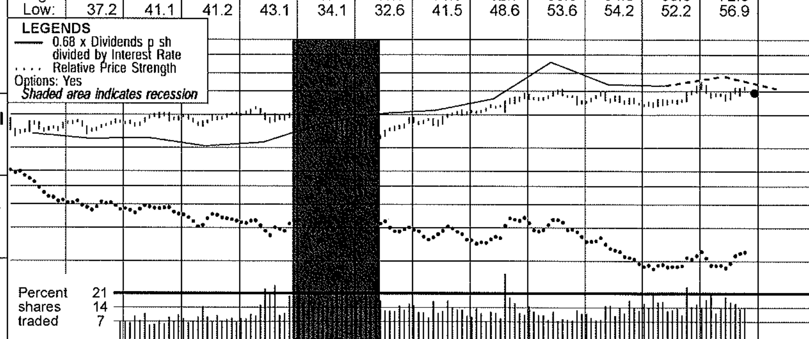
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

CON. EDISON NYSE-ED

RECENT PRICE 62.67 | P/E RATIO 16.3 (Trailing: 16.6, Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Raised 10/30/15
SAFETY 1 New 7/27/90
TECHNICAL 1 Raised 11/20/15
BETA .60 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3
Low:	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9



Target Price Range 2018 | 2019 | 2020
120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	7%
Low	55	(-10%)	1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	321	330	299
to Sell	265	284	290
Hld's(000)	152674	153088	154997

% TOT. RETURN 10/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.0	-1.3
3 yr.	23.7	49.3
5 yr.	63.8	73.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	*43.35*	*44.35*	**Revenues per sh**	*48.50*
5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	*7.85*	*8.20*	**"Cash Flow" per sh**	*9.25*
3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	*3.95*	*4.10*	**Earnings per sh** A	*4.50*
2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	*2.60*	*2.68*	**Div'd Decl'd per sh** B ■	*2.90*
3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	*11.50*	*13.05*	**Cap'l Spending per sh**	*10.50*
25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	*44.30*	*45.75*	**Book Value per sh** C	*50.50*
213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	*293.00*	*293.00*	**Common Shs Outst'g** D	*293.00*
14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	*Bold figures are*		**Avg Ann'l P/E Ratio**	*14.0*
.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	*Value Line*		**Relative P/E Ratio**	*.90*
4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	*estimates*		**Avg Ann'l Div'd Yield**	*4.6%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $13442 mill. **Due in 5 Yrs** $3531 mill.
LT Debt $11521 mill. **LT Interest** $553 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $18 mill.

Pension Assets-12/14 $11495 mill. **Oblig.** $15081 mill.

Pfd Stock None

Common Stock 293,192,258 shs.
as of 10/30/15
MARKET CAP: $18 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
11690	12137	13120	13583	13032	13325	12938	12188	12381	12919	*12700*	*13000*	**Revenues ($mill)**	*14200*
719.0	749.0	936.0	933.0	868.0	992.0	1062.0	1141.0	1157.0	1066.0	*1170*	*1215*	**Net Profit ($mill)**	*1330*
33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	*35.0%*	*34.0%*	**Income Tax Rate**	*34.0%*
2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	.5%	.5%	.3%	*1.0%*	*Nil*	**AFUDC % to Net Profit**	*Nil*
49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	*48.5%*	*49.5%*	**Long-Term Debt Ratio**	*48.5%*
49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	*51.5%*	*50.5%*	**Common Equity Ratio**	*51.5%*
14921	16515	16687	19160	20330	21952	21794	21933	22735	24207	*25125*	*26525*	**Total Capital ($mill)**	*28700*
17112	18445	19914	20874	22464	23863	25093	26939	28436	29827	*32075*	*34700*	**Net Plant ($mill)**	*40100*
6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	*6.0%*	*5.5%*	**Return on Total Cap'l**	*6.0%*
9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	*9.0%*	*9.0%*	**Return on Shr. Equity**	*9.0%*
9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	*9.0%*	*9.0%*	**Return on Com Equity** E	*9.0%*
2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	*3.0%*	*3.0%*	**Retained to Com Eq**	*3.0%*
74%	73%	63%	67%	71%	65%	66%	62%	62%	69%	*65%*	*65%*	**All Div'ds to Net Prof**	*64%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+.1	-1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	14344	14883	13568
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	382	385	366

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-2.5%	*2.0%*
"Cash Flow"	4.0%	4.5%	*4.0%*
Earnings	3.5%	2.5%	*3.0%*
Dividends	1.0%	1.0%	*2.5%*
Book Value	4.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3078	2771	3438	2901	12188
2013	3306	2767	3440	2868	12381
2014	3789	2911	3390	2829	12919
2015	3616	2788	3443	*2853*	*12700*
2016	*3650*	*2850*	*3500*	*3000*	*13000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.94	.73	1.49	.70	3.86
2013	1.16	.49	1.49	.79	3.93
2014	1.23	.63	1.49	.28	3.62
2015	1.26	.75	1.46	*.48*	*3.95*
2016	*1.20*	*.70*	*1.55*	*.65*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.60	.60	.60	.60	2.40
2012	.605	.605	.605	.605	2.42
2013	.615	.615	.615	.615	2.46
2014	.63	.63	.63	.63	2.52
2015	.65	.65	.65		

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 35% of revenues. '14 reported depreciation rates: 2.9%-3.1%. Has 14,600 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's earnings should advance this year and next. Income provided by various regulatory plans is one factor. Consolidated Edison Company of New York received a rate order that will take effect at the start of 2016. The company's Orange and Rockland Utilities unit also was granted rate relief that took effect at the start of November. ConEd is also benefiting from customer conversions from oil heat to gas heat. (The economics of gas heat are still favorable, despite the sharp drop in oil prices since mid-2014.) Economic growth is another plus. On the nonutility side, ConEd continues to invest in renewable energy projects. We have cut our 2015 earnings estimate by $0.05 a share, to $3.95, because third-quarter profits were slightly below our estimate. Our revised expectation remains within management's guidance of $3.90-$4.05 a share. For 2016, we are sticking with our forecast of $4.10 a share. Note that mark-to-market accounting items (included in our presentation) can skew the year-to-year comparisons.

We look for a dividend hike at the board meeting in January. This has been the pattern in recent years. Indeed, 2015 is ConEd's 41st consecutive year with a dividend increase. We estimate that the directors will boost the quarterly disbursement by $0.02 a share (3.1%), the same increase as in 2015. ConEd is targeting a payout ratio of 60%-70%.

The company has agreed to sell a small utility subsidiary. It will get $16 million for Pike Electric in Pennsylvania once the deal is completed (probably in the second half of 2016). ConEd took a charge of a cent a share in the September quarter as a result of the deal, which is included in our presentation.

ConEd stock provides a steady source of income for conservative investors. The dividend yield is slightly above average for a utility, but 3- to 5-year total return potential is unexciting. The equity has our top rank for Safety. That said, investors should be aware of litigation surrounding a gas line explosion in Manhattan that killed eight people in March of 2014. So far, this does not appear to be weighing on the stock price, and the company has not taken a reserve.

Paul E. Debbas, CFA *November 20, 2015*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; gain on discontinued operations: '08, $1.01. '14 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '14: $33.50/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '14: 9.2% elec., 9.3% gas & steam; O&R in '15: 9.0%; earned on avg. com. eq., '14: 8.6%. Regulatory Climate: Below Average.

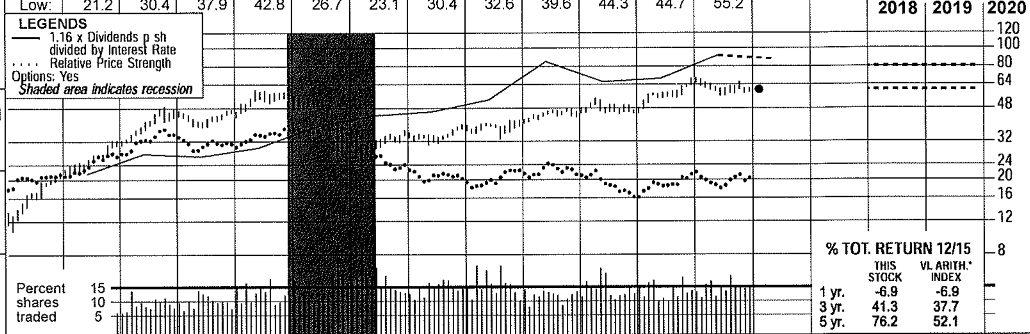
Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **60.12** | P/E RATIO **17.0** (Trailing: 13.8 Median: 12.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS **3** Lowered 11/7/14
SAFETY **2** Raised 5/3/13
TECHNICAL **3** Lowered 1/1/16
BETA .70 (1.00 = Market)

High:	32.5	49.2	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	
Low:	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+35%)	10%
Low	60	(Nil)	4%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	0	0	0	0	0	0
Options	2	0	1	0	0	0	1	0	1
to Sell	2	0	1	0	0	1	1	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	248	226	242
to Sell	216	228	218
Hld's(000)	263836	266122	268851

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.9	-6.9
3 yr.	41.3	37.7
5 yr.	76.2	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	*37.45*	*39.60*	Revenues per sh	*46.00*
7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	*10.10*	*10.70*	"Cash Flow" per sh	*13.00*
2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	*3.80*	*4.10*	Earnings per sh A	*5.25*
1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	*1.95*	Div'd Decl'd per sh B ■	*2.45*
3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	*12.10*	*11.65*	Cap'l Spending per sh	*13.25*
15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	*34.55*	*36.55*	Book Value per sh C	*44.00*
347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	*16.1*		Avg Ann'l P/E Ratio	*13.5*
.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	*.80*		Relative P/E Ratio	*.85*
4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $12406 mill. **Due in 5 Yrs** $3094 mill.
LT Debt $10957 mill. **LT Interest** $499 mill.
(LT interest earned: 5.1x)
Leases, Uncapitalized Annual rentals $473 mill.
Pens. Assets-12/14 $3454 mill. **Oblig.** $4517 mill.
Pfd Stock $2022 mill. **Pfd Div'd** $113 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 10/23/15**
MARKET CAP: $20 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
11852	12622	13113	14112	12374	12409	12760	11862	12581	13413	*12200*	*12900*	Revenues ($mill)	*15000*
1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	*1375*	*1470*	Net Profit ($mill)	*1860*
26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	*20.5%*	*26.0%*	Income Tax Rate	*26.0%*
4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	*45.0%*	*44.0%*	Long-Term Debt Ratio	*44.0%*
40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	*46.5%*	*47.5%*	Common Equity Ratio	*49.0%*
16167	17725	18375	21374	21185	23861	24773	20422	21516	23216	*24325*	*25075*	Total Capital ($mill)	*29300*
14469	15913	17403	18969	21966	24778	32116	30273	30455	32981	*34875*	*36550*	Net Plant ($mill)	*42200*
9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	*11.0%*	*11.5%*	Return on Com Equity E	*12.0%*
12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	*6.0%*	*6.0%*	Retained to Com Eq	*6.5%*
29%	31%	33%	35%	41%	40%	43%	32%	40%	37%	*50%*	*51%*	All Div'ds to Net Prof	*49%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	-.3	+2.1
Avg. Indust. Use (MWH)	763	791	788
Avg. Indust. Revs. per KWH (¢)	7.50	8.00	8.86
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21981	22534	23055
Annual Load Factor (%)	52.7	52.1	52.3
% Change Customers (yr-end)	+.4	+.6	+.6
Fixed Charge Cov. (%)	308	295	306

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	-1.0%	*3.0%*
"Cash Flow"	7.0%	3.5%	*5.5%*
Earnings	10.0%	4.5%	*3.5%*
Dividends	--	2.5%	*10.0%*
Book Value	6.5%	2.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	2415	2653	3734	3060	11862
2013	2632	3046	3960	2943	12581
2014	2926	3016	4356	3115	13413
2015	2512	2908	3763	*3017*	*12200*
2016	*2750*	*3100*	*3900*	*3150*	*12900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.54	.55	1.09	2.39	4.55
2013	.78	.78	1.41	.81	3.78
2014	.61	1.07	1.51	1.15	4.33
2015	.91	1.15	1.15	*.59*	*3.80*
2016	*.90*	*.90*	*1.50*	*.80*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.325	.325	.325	.325	1.30
2013	.3375	.3375	.3375	.3375	1.35
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 4.9 mill. customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Discontinued Edison Mission Energy (independent power producer) in '12. Elec. revenue breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 8%; nuclear, 6%; hydro, 2%; purchased, 84%. Fuel costs: 42% of revs. '14 reported deprec. rate: 4.0%. Has 13,700 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's utility subsidiary received an order in its general rate case. In November, the California Public Utilities Commission (CPUC) reduced Southern California Edison's rates by $451 million, retroactive to the start of 2015. A provision in the decision will also force the company to take an aftertax charge of $382 million ($1.17 a share) to write off some regulatory assets. On a positive note, SCE's tariffs rose by $209 million at the beginning of 2016 and will climb by $272 million at the start of 2017.

The utility has another regulatory matter pending. SCE was required to put forth a Distribution Resources Plan, which deals with issues such as integrating distributed generation with the electric grid. Its current estimate is that it will spend $347 million-$560 million through 2017 and $1.405 billion-$2.585 billion from 2018 through 2020. The former amount would be recorded for future recovery through a memorandum account, the latter through a general rate case. When the CPUC will rule on the utility's proposal is not known.

One more rate filing is upcoming. SCE will file another general rate case in September. New tariffs will take effect at the start of 2018. The company (and other utilities in California) were granted a one-year postponement by the CPUC for their next cost-of-capital cases, which will be filed in April of 2017.

We estimate that earnings will increase solidly in 2016. The utility will benefit from the rate increase and growth in its rate base. In fact, the rate base is likely to advance 7%-8% in 2016 and 2017.

The board of directors raised the dividend significantly, effective with the January payment. The board boosted the annual disbursement by $0.25 a share (15%). The company has established a target of a 45%-55% payout ratio of SCE's earnings.

The stock's dividend yield is below average, by utility standards. This reflects Edison International's strong dividend growth prospects though the end of the decade. Total return potential over the that period is a cut above the industry mean.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, (*$1.17*); gains (loss) from discont. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 13¢. '12 & '14 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $23.36/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '14: 13.8%. Regul. Clim.: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

EL PASO ELECTRIC NYSE-EE

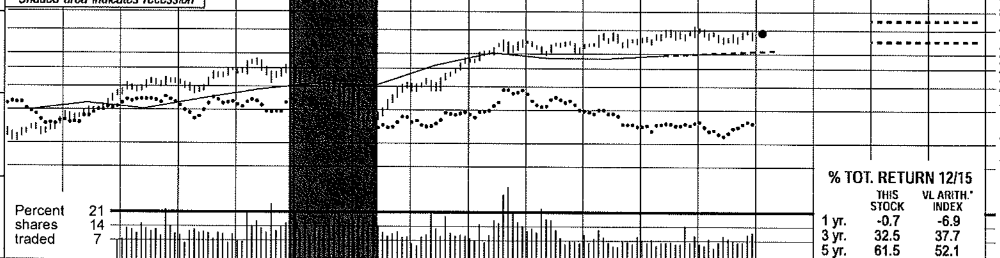
RECENT PRICE 38.70 | P/E RATIO 18.1 (Trailing: 18.3; Median: 15.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 11/13/15
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Lowered 1/1/16
BETA .75 (1.00 = Market)

High:	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3
Low:	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8

LEGENDS
—— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range
2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	5	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	88	76	78
to Sell	74	71	63
Hld's(000)	38975	39499	39588

Percent shares traded 21 / 14 / 7

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.7	-6.9
3 yr.	32.5	37.7
5 yr.	61.5	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	*21.00*	*22.15*	Revenues per sh	*26.75*
2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	*6.05*	*6.25*	"Cash Flow" per sh	*8.00*
.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	*2.05*	*2.10*	Earnings per sh A	*2.75*
--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	*1.23*	Div'd Decl'd per sh B	*1.40*
1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	*7.90*	*7.75*	Cap'l Spending per sh	*7.25*
7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	*25.20*	*26.00*	Book Value per sh C	*29.50*
57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	*40.50*	*40.65*	Common Shs Outst'g D	*41.10*
9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	*18.1*		Avg Ann'l P/E Ratio	*14.5*
.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	*.90*		Relative P/E Ratio	*.90*
--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1253.0 mill. **Due in 5 Yrs** $201.9 mill.
LT Debt $1134.3 mill. **LT Interest** $68.2 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/14 $272.9 mill. **Oblig.** $341.1 mill.

Pfd Stock None

Common Stock 40,426,668 shs. as of 10/31/15

MARKET CAP: $1.6 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	*850*	*900*	Revenues ($mill)	*1100*
36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	*85.0*	*85.0*	Net Profit ($mill)	*115*
33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	*30.0%*	*31.0%*	Income Tax Rate	*31.0%*
15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	*24.0%*	*24.0%*	AFUDC % to Net Profit	*13.0%*
52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	*52.5%*	*55.0%*	Long-Term Debt Ratio	*55.5%*
47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	*47.5%*	*45.0%*	Common Equity Ratio	*44.5%*
1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	*2155*	*2340*	Total Capital ($mill)	*2725*
1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	*2645*	*2790*	Net Plant ($mill)	*3050*
4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	*5.5%*	*5.0%*	Return on Total Cap'l	*6.0%*
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	*8.0%*	*8.0%*	Return on Shr. Equity	*9.5%*
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	*8.0%*	*8.0%*	Return on Com Equity E	*9.5%*
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
--	--	--	--	--	--	26%	43%	47%	49%	*56%*	*59%*	All Div'ds to Net Prof	*49%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.7	+.4	-1.6
Avg. Indust. Use (MWH)	21659	21908	21505
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1765	1852	1879
Peak Load, Summer (Mw)	1688	1750	1766
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.3	+1.3
Fixed Charge Cov. (%)	302	280	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	4.5%	1.5%	*3.5%*
"Cash Flow"	6.5%	7.5%	*5.5%*
Earnings	13.5%	6.5%	*3.5%*
Dividends	--	--	*5.0%*
Book Value	8.5%	8.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.7	219.5	289.7	*177.1*	*850*
2016	*175*	*240*	*300*	*185*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	*.04*	*2.05*
2016	*.05*	*.65*	*1.25*	*.15*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 35%; coal, 5%; purchased, 13%. Fuel costs: 34% of revenues. '14 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has rate applications pending in Texas and New Mexico. The utility wants to place capital expenditures into the rate base, including its spending on the first two units (88 megawatts each) of a four-unit gas-fired generating station. In Texas, El Paso Electric is seeking a rate hike of $70.5 million, based on a return of 10.1% on a common-equity ratio of 49.52%. The staff of the Texas commission is recommending an increase of $54.3 million, based on a 9.5% ROE, and the city of El Paso is proposing a hike of $23.5 million, based on a 9.1% ROE. In New Mexico, El Paso Electric is asking for $6.4 million, based on a return of 9.95% on a common-equity ratio of 49.29%. The commission's staff is recommending a $3.2 million raise, based on a 9.22% ROE. Although settlements cannot be ruled out, it appears as if each case will be fully litigated, with orders being issued early in the second quarter of 2016.

We have adjusted our earnings estimates for 2015 and 2016. The first two units of the aforementioned generating plant are in service, but are not yet in the rate base. Thus, El Paso Electric is incurring costs (such as depreciation) that are not being recovered. This results in regulatory lag for the utility. We overestimated the effects of regulatory lag in the third quarter of 2015, but underestimated them in the fourth quarter of 2015 and first period of 2016. Because third-quarter profits (aided by favorable weather patterns) exceeded our expectation, we have raised our full-year estimate by $0.10 a share, to $2.05. Our revised estimate is within the company's targeted range of $1.95-$2.10 a share. On the other hand, we have cut our 2016 forecast by $0.10 a share due to our lowered expectation for the March period.

Finances are sound. The fixed-charge coverage, common-equity ratio, and return on equity are comparable with the norms for the electric utility industry.

The dividend yield of El Paso Electric stock is low, by utility standards. This reflects, in part, the company's good dividend growth prospects through 2018-2020. However, with the recent quotation within our 3- to 5-year Target Price Range (like that of many utility issues), total return potential is lackluster.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '14: $112.1 mill., $2.78/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '14: 9.5%. Regulatory Climate: Average.

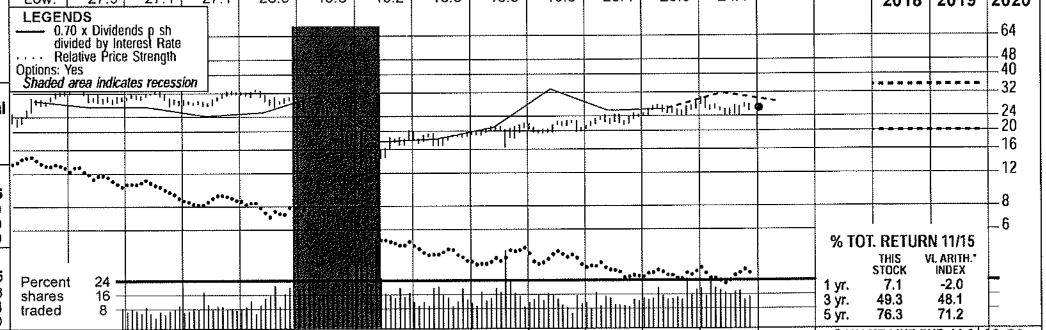
Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	85

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE 26.56 | P/E RATIO 17.1 (Trailing: 19.8 / Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 12/18/15
SAFETY 3 Lowered 12/26/08
TECHNICAL 1 Raised 12/18/15
BETA .85 (1.00 = Market)

High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	20	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	9	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	125	122	108
to Sell	148	125	134
Hld's(000)	121848	130044	125340

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.1	-2.0
3 yr.	49.3	48.1
5 yr.	76.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	*15.85*	*17.10*	Revenues per sh	*19.25*
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	*3.95*	*4.60*	"Cash Flow" per sh	*6.00*
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	*1.35*	*1.75*	Earnings per sh A	*2.00*
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	*1.00*	*1.06*	Div'd Decl'd per sh B ■	*1.20*
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	*5.20*	*4.05*	Cap'l Spending per sh	*3.75*
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	*23.60*	*24.30*	Book Value per sh C	*26.75*
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	*154.50*	*154.75*	Common Shs Outst'g D	*155.50*
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	*Value Line*		Relative P/E Ratio	*.85*
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	*2450*	*2650*	Revenues ($mill)	*3000*
						164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	*215*	*275*	Net Profit ($mill)	*315*
						18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	*5.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	*51.0%*	*47.5%*	Long-Term Debt Ratio	*48.0%*
						50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	*48.5%*	*52.0%*	Common Equity Ratio	*51.5%*
						2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	*7525*	*7255*	Total Capital ($mill)	*8050*
						2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	*8690*	*8875*	Net Plant ($mill)	*9050*
						8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	*4.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	*6.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
						13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	*6.0%*	*7.5%*	Return on Com Equity E	*7.5%*
						3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	*1.5%*	*3.0%*	Retained to Com Eq	*3.0%*
						76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	*73%*	*60%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $4105.7 mill. **Due in 5 Yrs** $1472.6 mill.
LT Debt $3763.5 mill. **LT Interest** $188.9 mill.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $14.2 mill.
Pension Assets-12/14 $730.0 mill.
Oblig. $1186.8 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,369,354 shs.
as of 11/2/15
MARKET CAP: $4.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.2	+.4
Avg. Indust. Use (MWH)	1443	1424	1455
Avg. Indust. Revs. per KWH (¢)	6.23	6.80	6.79
Capacity at Peak (Mw)	6719	NA	NA
Peak Load, Summer (Mw)	5653	NA	NA
Annual Load Factor (%)	49.6	NA	NA
% Change Customers (avg.)	+.2	+.7	+.9
Fixed Charge Cov. (%)	235	267	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.5%	-6.5%	*3.5%*
"Cash Flow"	-2.0%	1.5%	*8.0%*
Earnings	-4.0%	2.5%	*5.0%*
Dividends	-6.0%	-8.5%	*6.0%*
Book Value	4.5%	2.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	781.4	*510.5*	*2450*
2016	*600*	*650*	*850*	*550*	*2650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	.82	*.13*	*1.35*
2016	*.20*	*.40*	*1.00*	*.15*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 844,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary received a rate order in Kansas. Kansas City Power & Light was granted a tariff hike of $48.7 million (9.0%), based on a return of 9.3% on a common-equity ratio of 50.48%. New rates took effect at the start of October. KCP&L also received a rate increase of $89.7 million (11.8%), based on a 9.5% return on a 50.09% common-equity ratio, in mid-September.

There were good and bad aspects to the rate orders. KCP&L received more than 75% of what it requested, and will earn a return on its entire investment in an environmental upgrade to a coal-fired plant. The utility was also granted a fuel-adjustment mechanism in Missouri. (It already had one in Kansas.) However, the company did not get other regulatory mechanisms it sought in Missouri, and is disappointed with the low allowed ROEs. It has appealed these issues to the courts in Missouri and Kansas.

We have cut our 2015 earnings estimate by a nickel a share. Third-quarter profits fell short of our estimate. Management narrowed its share-earnings guidance from $1.35-$1.60 to $1.35-$1.45, and our revised profit estimate is at the low end of this range. In recent years, the company has been earning mediocre ROEs due to the effects of regulatory lag. The rate orders came too late to have much effect on earnings this year, but . . .

We continue to expect a significant profit increase in 2016. The rate orders should help the utility reduce (but won't eliminate) the regulatory lag problem. Our forecast would result in a 30% bottom-line increase over our 2015 estimate. Great Plains Energy will put forth 2016 guidance in its conference call in late February.

The board of directors has raised the dividend. The board boosted the annual disbursement by $0.07 a share (7.1%), effective with the fourth-quarter payment. Great Plains is now targeting a payout ratio in a range of 55%-70%, but wants to narrow this to 60%-70% after 2016.

Great Plains Energy stock has an average dividend yield for a utility. With the recent price near the midpoint of our 3- to 5-year Target Price Range, total return potential is low.

Paul E. Debbas, CFA — *December 18, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $7.81/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '15: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '14: 6.8%. Regulatory Climate: Average.

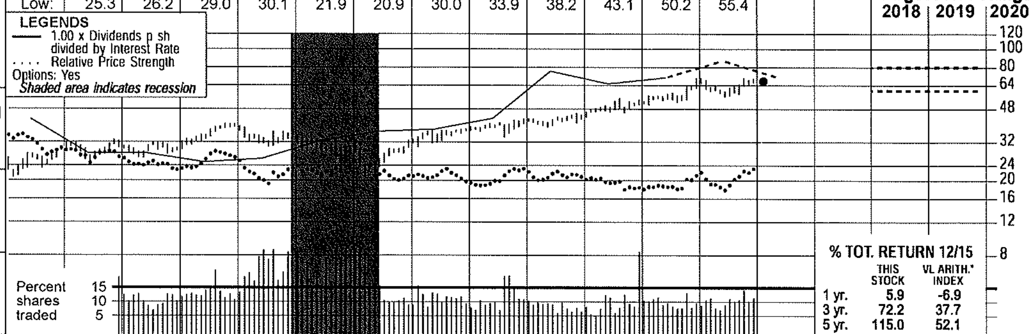
Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	75

IDACORP, INC. NYSE-IDA

RECENT PRICE 67.59 | P/E RATIO 17.8 (Trailing: 17.2; Median: 14.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 5/15/15
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Lowered 12/4/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5
Low:	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	7%
Low	60	(-10%)	1%

Target Price Range
2018 | 2019 | 2020

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	2	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	1	1	1	1	0	1	1	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	106	101	106
to Sell	92	100	95
Hld's(000)	37715	37671	67529

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.9	-6.9
3 yr.	72.2	37.7
5 yr.	115.0	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	*24.95*	*26.05*	Revenues per sh	*27.95*
4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.49	*6.45*	*6.70*	"Cash Flow" per sh	*7.50*
2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	*3.83*	*3.95*	Earnings per sh A	*4.25*
1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	*2.03*	Div'd Decl'd per sh B† ■	*2.45*
2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	*6.05*	*6.05*	Cap'l Spending per sh	*6.00*
20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	*40.70*	*42.60*	Book Value per sh C	*47.05*
37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	*50.30*	*50.30*	Common Shs Outst'g D	*50.30*
12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	*16.4*		Avg Ann'l P/E Ratio	*16.0*
.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.78	*.83*		Relative P/E Ratio	*1.00*
6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1741.9 mill. **Due in 5 Yrs** $264.5 mill.
LT Debt $1741.9 mill. **LT Interest** $81.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/14 $559.7 mill.
Oblig. $844.8 mill.

Pfd Stock None

Common Stock 50,340,688 shs.
as of 10/23/15

MARKET CAP: $3.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	*1255*	*1310*	Revenues ($mill)	*1405*
63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	*195*	*200*	Net Profit ($mill)	*215*
16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	13.4%	28.3%	8.1%	*23.0%*	*23.0%*	Income Tax Rate	*30.0%*
4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	4.4%	*7.5%*	*8.0%*	AFUDC % to Net Profit	*9.5%*
50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	*3660*	*3840*	Total Capital ($mill)	*4330*
2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	*4095*	*4300*	Net Plant ($mill)	*4975*
4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.6%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Com Equity E	*8.5%*
1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
80%	51%	64%	55%	46%	41%	36%	41%	43%	46%	*52%*	*53%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	+3.8	+1.4
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.63	5.21	5.68
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3245	3407	3184
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.1	+1.5	+1.4
Fixed Charge Cov. (%)	283	329	287

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	3.0%	*2.5%*
"Cash Flow"	4.5%	6.5%	*2.5%*
Earnings	9.0%	10.0%	*1.0%*
Dividends	--	5.5%	*6.0%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	289.8	1282.5
2015	279.4	336.3	369.2	*270.1*	*1255*
2016	*295*	*335*	*395*	*285*	*1310*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	*.59*	*3.83*
2016	*.55*	*1.20*	*1.63*	*.57*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a regulated electric utility that serves more than 520,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon. Operates 17 hydroelectric projects on the Snake River and its tributaries. Also owns three natural gas-fired plants in Idaho and has stakes in three coal-fired facilities (in NV, OR, and WY). Revenue breakdown: residential, 45%; commercial, 27%; industrial, 16%; other, 12%. Fuel sources: hydro, 35%; coal, 34%; natural gas, 7%; purchased power, 24%. '14 depr. rate: 3.8%. Has 2,021 employees. Chairman: Robert A. Tinstman. Pres. & CEO: Darrel T. Anderson. Inc.: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Tel.: 208-388-2200. Web: www.idacorpinc.com.

We now suspect that 2015 was a slightly down year for IDACORP. Previously, it looked like the electricity provider to some 500,000 customers in Idaho and Oregon could perhaps eke out a small bottom-line gain for the year that was. However, tough tax-rate comparisons, in particular, probably made for a modest falloff in share net.

The outlook for 2016 seems pretty decent, though. To wit, recent projections point to increased economic activity and population growth within the utility's service area, both of which augur well for power demand. Notably, growth in gross area product (i.e., regional GDP) was recently expected to accelerate from 4.8% in 2015 to around 6.3% over the next 12 months. Meantime, housing construction, including both single-family and multi-family builds, was also forecasted to experience a pick up of sorts.

Major capital investments should drive longer-term rate-base and earnings expansion. Case in point, IDACORP still plans to participate in the construction of a 500-kilovolt transmission line that would run from a substation near Melba, Idaho to Boardman, Oregon. The project is currently slated for completion in 2022 and is expected to cost up to $1.2 billion, some 21% of which would be IDACORP's stake. Importantly, the Boardman line should offer fairly stable power supply in the event that dry conditions limit hydroelectric capacity.

IDACORP has increased its quarterly dividend by 70%, to $0.51 a share, over the past four years. And more increases are likely on the way. Indeed, management recently urged the utility's board of directors to sign off on annual increases of 5% or more (likely above the level of sustainable earnings growth), so that the payout ratio approaches the higher end of a recently targeted range of between 50% and 60%.

IDACORP shares are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. With much of the good news seemingly already reflected in the stock price, we would look elsewhere for utility industry exposure.

Nils C. Van Liew *January 29, 2016*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early February. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '14: $25.26/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	95

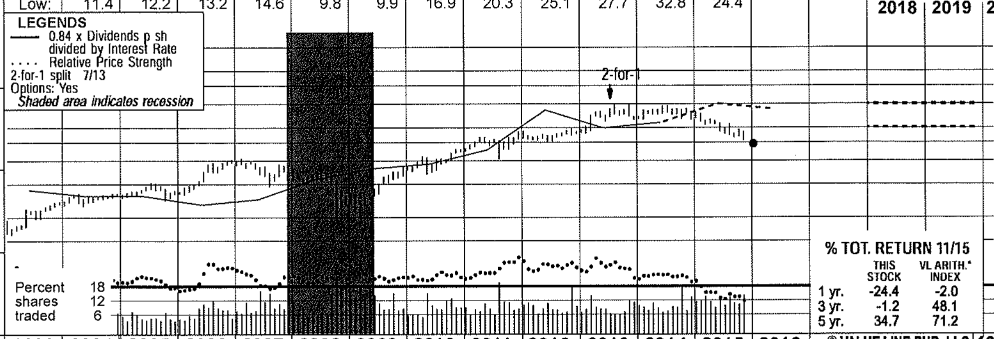
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 24.62 | P/E RATIO 13.8 (Trailing: 13.3 Median: 14.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 12/18/15
SAFETY 2 Lowered 12/18/15
TECHNICAL 2 Raised 12/18/15
BETA .95 (1.00 = Market)

High:	13.5	15.3	20.3	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5
Low:	11.4	12.2	13.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.4

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+60%)	16%
Low	30	(+20%)	9%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	166	173	170
to Sell	146	142	152
Hld's(000)	123149	125076	127844

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-24.4	-2.0
3 yr.	-1.2	48.1
5 yr.	34.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.95	21.17	20.40	19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	***11.25***	***12.20***	Revenues per sh	***13.75***
2.03	2.07	1.81	1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	***3.30***	***3.45***	"Cash Flow" per sh	***4.00***
.97	.95	.65	.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	***1.75***	***1.85***	Earnings per sh A	***2.25***
.67	.67	.67	.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	***1.05***	***1.16***	Div'd Decl'd per sh B ▪	***1.55***
1.16	1.15	1.44	1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	***3.00***	***3.90***	Cap'l Spending per sh	***2.25***
6.55	6.83	6.67	6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	***16.60***	***17.30***	Book Value per sh C	***19.25***
155.73	155.84	155.98	157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	***200.00***	***200.50***	Common Shs Outst'g D	***202.00***
12.1	10.6	17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	***16.0***
.69	.69	.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	*Value Line*		Relative P/E Ratio	***1.00***
5.7%	6.6%	5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	*estimates*		Avg Ann'l Div'd Yield	***4.3%***
						5948.2	4005.6	3797.6	4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	***2250***	***2450***	Revenues ($mill)	***2800***
						166.1	226.1	244.2	231.4	258.3	295.3	342.9	355.0	387.6	395.8	***345***	***370***	Net Profit ($mill)	***435***
						30.2%	34.8%	32.3%	30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	***27.0%***	***29.0%***	Income Tax Rate	***29.0%***
						1.3%	3.8%	1.6%	1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	***4.0%***	***5.0%***	AFUDC % to Net Profit	***2.0%***
						49.5%	45.6%	44.4%	53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	***45.5%***	***46.0%***	Long-Term Debt Ratio	***50.0%***
						50.5%	54.4%	55.6%	46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	***54.5%***	***54.0%***	Common Equity Ratio	***50.0%***
						2726.6	2950.1	3025.5	4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	***6075***	***6425***	Total Capital ($mill)	***7750***
						3567.4	3867.5	4246.3	5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	***7265***	***7730***	Net Plant ($mill)	***8275***
						7.6%	9.1%	9.5%	7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.0%***
						12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	***10.5%***	***10.5%***	Return on Shr. Equity	***11.0%***
						12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	***10.5%***	***10.5%***	Return on Com Equity E	***11.0%***
						3.4%	6.6%	7.1%	5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	***4.0%***	***4.0%***	Retained to Com Eq	***3.0%***
						72%	53%	51%	55%	53%	48%	43%	44%	43%	47%	***60%***	***63%***	All Div'ds to Net Prof	***72%***

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2755.5 mill. **Due in 5 Yrs** $835.5 mill.
LT Debt $2645.5 mill. **LT Interest** $138.8 mill.
(LT interest earned: 4.5x)

Leases, Uncapitalized Annual rentals $6.7 mill.

Pension Assets-12/14 $679.8 mill. **Oblig.** $725.0 mill.

Pfd Stock None

Common Stock 199,702,572 shs.

MARKET CAP: $4.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.7	-.7
Avg. Indust. Use (MWH)	776	779	770
Avg. Indust. Revs. per KWH (¢)	5.07	5.44	5.73
Capacity at Peak (Mw)	7139	NA	NA
Peak Load, Summer (Mw)	7000	6341	6339
Annual Load Factor (%)	51.6	NA	NA
% Change Customers (yr-end)	+1.1	+1.1	+1.0
Fixed Charge Cov. (%)	404	367	356

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-4.0%	-4.5%	*NMF*
"Cash Flow"	6.5%	7.0%	*2.0%*
Earnings	8.5%	8.0%	*3.0%*
Dividends	2.5%	4.5%	*10.0%*
Book Value	8.5%	9.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	840.7	855.0	1113.4	862.1	3671.2
2013	901.4	734.2	723.2	508.9	2867.7
2014	560.4	611.8	754.7	526.2	2453.1
2015	480.1	549.9	719.8	***500.2***	***2250***
2016	***550***	***575***	***775***	***550***	***2450***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.19	.48	.94	.20	1.79
2013	.12	.46	1.08	.29	1.94
2014	.25	.50	.94	.29	1.98
2015	.22	.44	.90	***.19***	***1.75***
2016	***.20***	***.50***	***.95***	***.20***	***1.85***

Cal-endar	QUARTERLY DIVIDENDS PAID B ▪ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.1875	.1875	.1875	.1875	.75
2012	.19675	.19675	.19675	.19675	.79
2013	.20875	.20875	.20875	.20875	.84
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 819,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 26.3% of Enable Midstream Partners. Electric revenue breakdown: residential, 42%; commercial, 26%; industrial, 19%; other, 13%. Generating sources: coal, 44%; gas, 23%; wind, 5%; purchased, 28%. Fuel costs: 45% of revenues. '13 reported depreciation rate (utility): 2.8%. Has 3,300 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary was disappointed with the rejection of its environmental compliance plan by the Oklahoma Corporation Commission (OCC). Oklahoma Gas and Electric had proposed a $1.1 billion plan, including $500 million for scrubbers on two coal-fired units. The OCC was probably reluctant to allow the utility to recover its costs through riders on customers' bills. OG&E plans to ask the OCC to reconsider at least the scrubber portion of the plan.

This is not the only problem the company has faced this year. Its investment in Enable Midstream Partners, a midstream gas master limited partnership in which it has a 26.3% stake, has not turned out as well as OGE had expected due to the sharp drop in commodity prices since mid-2014. Enable still provided $140 million in distributions for OGE this year, but distribution growth has come at a token pace in recent quarters. This is the main reason why OGE stock has performed so poorly this year, having declined about 30% in value since the start of 2015. We have lowered the company's Financial Strength rating and the stock's Safety rank a notch each, to A and 2 (Above Average), respectively.

The utility will soon file rate cases in Oklahoma and Arkansas. The filing in Oklahoma is not related to the rejection of the aforementioned environmental plan. OG&E seeks to place 300 megawatts of capacity back in the rate base (it had been used to supply a wholesale contract) and recover capital expenditures and expense increases since the utility's last rate case. New rates should take effect by the start of next summer. A filing in Arkansas is planned for early 2016.

Despite the situation at Enable, OGE is sticking with its plan to raise the dividend by 10% annually through 2019. The board of directors declared such an increase this year, and our 3- to 5-year projections are based on a continuation of this policy.

OGE stock has an attractive valuation for a utility issue. The dividend yield and total return potential to 2018-2020 are above the industry averages. Investors must be willing to assume the risks associated with the interest in Enable, however.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 20¢; '03, 7¢; '04, 3¢; '15, 35¢; gains on discontinued operations: '02, 6¢; '05, 25¢; '06, 20¢. '13 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ▪ Div'd reinvestment plan available. (C) Incl. deferred charges. In '14: $2.06/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '12: 10.2%; in AR in '11: 9.95%; earned on avg. com. eq., '14: 12.6%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	75
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE **26.56** | P/E RATIO **16.2** (Trailing: 18.6 Median: 23.0) | RELATIVE P/E RATIO **0.92** | DIV'D YLD **4.7%** | VALUE LINE

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4
Low:	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8

TIMELINESS 4 Lowered 11/20/15
SAFETY 3 Lowered 12/24/10
TECHNICAL 4 Lowered 12/11/15
BETA .85 (1.00 = Market)

2018-20 PROJECTIONS

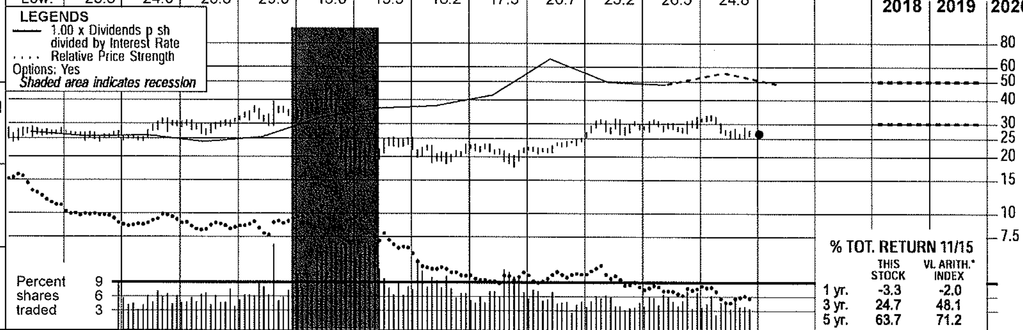
	Price	Gain	Ann'l Total Return
High	50	(+90%)	20%
Low	30	(+15%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	50	49	53
to Sell	58	53	50
Hld's(000)	12560	12614	12771



% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.3	-2.0
3 yr.	24.7	48.1
5 yr.	63.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	*21.05*	*21.80*	Revenues per sh	*29.15*
2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	*3.15*	*3.60*	"Cash Flow" per sh	*4.50*
1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	*1.60*	*1.75*	Earnings per sh A	*2.25*
.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	*1.23*	*1.25*	Div'd Decl'd per sh B ■	*1.32*
1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	*4.20*	*4.35*	Cap'l Spending per sh	*4.75*
10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	*16.05*	*16.65*	Book Value per sh C	*18.10*
23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	*38.00*	*39.00*	Common Shs Outst'g D	*42.00*
13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	*Value Line*		Relative P/E Ratio	*1.15*
4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $585.5 mill. **Due in 5 Yrs** $87.0 mill.
LT Debt $498.3 mill. **LT Interest** $28.0 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/14 $244.6 mill. **Oblig.** $311.7 mill.
Pfd Stock None

Common Stock 37,743,953 shs.
as of 10/31/15
MARKET CAP: $1.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	*800*	*850*	Revenues ($mill)	*1225*
52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	*60.0*	*70.0*	Net Profit ($mill)	*95.0*
34.6%	34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	*45.5%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	*54.5%*	*54.5%*	Common Equity Ratio	*53.0%*
738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	*1120*	*1190*	Total Capital ($mill)	*1435*
697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	*1400*	*1500*	Net Plant ($mill)	*1750*
8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	*10.0%*	*11.0%*	Return on Shr. Equity E	*12.5%*
11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	*10.0%*	*11.0%*	Return on Com Equity	*12.5%*
4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*5.0%*
63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	*79%*	*71%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+5.8	+4.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	359	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-2.0%	-8.5%	4.0%
"Cash Flow"	-1.0%	-.5%	7.5%
Earnings	-2.0%	2.0%	9.0%
Dividends	1.0%	--	1.5%
Book Value	1.0%	-4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	*209*	*800*
2016	*215*	*205*	*210*	*220*	*850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	*.45*	*1.60*
2016	*.42*	*.35*	*.48*	*.50*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (42%), and South Dakota (8%). Electric rev. breakdown, '14: residential, 32%; commercial & farms, 37%; industrial, 25%; other, 6%. Fuel costs: 16.6% of revenues. Also has operations in manufacturing and plastics. 2014 depr. rate: 2.9%. Has 1,893 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.3%; Vanguard Group, Inc., 6.6%; BlackRock, Inc., 5.5% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have traded in a fairly narrow range in recent months, following a selloff earlier in the year. The company reported modest top-line growth for the September period. Electric revenue increased at a good pace, but this was partly offset by lower Product Sales revenue. Still, operating expenses remained muted. Excluding a discontinued gain of $0.07 per share in the prior-year period, earnings from continuing operations would have advanced nicely.

The Electric segment should perform well going forward. Otter Tail Power Company is benefiting from rider recovery increases, greater costs recovered, and healthy customer demand. Earnings from capital investments should also grow. The utility continues to analyze the Environmental Protection Agency's Clean Power Plan to regulate carbon dioxide from existing power plants. Otter Tail will not know the rule's impact on its business until implementation plans are formulated at the state level.

Near-term prospects elsewhere appear mixed. Performance at the Plastics business may well continue to be hurt by weakness in the price of polyvinyl chloride pipe, owing to lower resin prices. Still, we expect a lower cost of product sold will benefit earnings here. Meantime, results at metal fabricator subsidiary BTD Manufacturing should continue to be affected by weakness in agriculture and energy markets, and a reduction in scrap-metal revenue related to lower commodity prices. Performance at this line ought to improve down the road, assuming a more favorable operating climate. Upon completion, the expansion of BTD's Minnesota facilities should enable this business to improve sales by expanding its services. The recent acquisition of Georgia-based Impulse Manufacturing brings strong fabrication capabilities and allows BTD to accelerate its plans to expand into the Southeast to serve that region's growing customer base.

This stock is untimely. But we envision healthy improvement in revenues and share earnings for the company out to 2018-2020. From the recent quotation, this issue offers good total return potential for the coming years. This is supported by a healthy dividend yield.

Michael Napoli, CFA *December 18, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due in February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '14: $42.7 mill., $1.15/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	50

PG&E CORP. NYSE-PCG

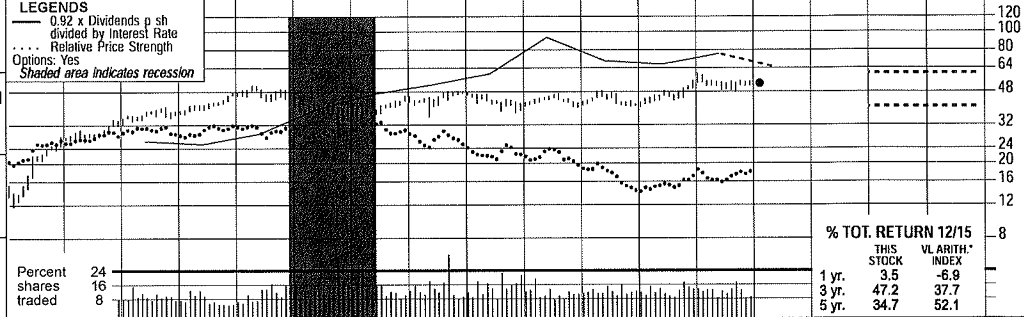
RECENT PRICE 52.98 | P/E RATIO 23.0 (Trailing: 26.5, Median: 15.0) | RELATIVE P/E RATIO 1.40 | DIV'D YLD 3.4% | VALUE LINE

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2	60.2
Low:	25.9	31.8	36.3	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3

TIMELINESS 3 Raised 11/13/15
SAFETY 3 Lowered 2/3/12
TECHNICAL 3 Lowered 1/1/16
BETA .70 (1.00 = Market)

LEGENDS
—— 0.92 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	40	(-25%)	-2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	1
to Sell	4	0	1	0	0	1	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	252	238	248
to Sell	226	219	217
Hld's(000)	383113	385342	399742

Percent shares traded 24 / 16 / 8

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.5	-6.9
3 yr.	47.2	37.7
5 yr.	34.7	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.60	33.95	Revenues per sh	38.25
7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.65	8.95	"Cash Flow" per sh	10.75
2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	3.06	1.90	3.15	Earnings per sh A	4.25
1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.82	Div'd Decl'd per sh B ■ †	2.20
4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.80	11.10	Cap'l Spending per sh	11.50
19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.50	35.40	Book Value per sh C	41.75
360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	475.91	491.00	505.00	Common Shs Outst'g D	520.00
13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	15.0	27.8		Avg Ann'l P/E Ratio	12.0
.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.79	1.40		Relative P/E Ratio	.75
4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%		Avg Ann'l Div'd Yield	4.4%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $16426 mill. Due in 5 Yrs $3654 mill.
LT Debt $15545 mill. LT Interest $732 mill.
Incl. $69 mill. capitalized leases.
(LT interest earned: 3.5x)
Pension Assets-12/14 $14216 mill.
Oblig. $16696 mill.
Pfd Stock $252 mill. Pfd Div'd $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 490,453,856 shs. as of 10/20/15
MARKET CAP: $26 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
11703	12539	13237	14628	13399	13841	14956	15040	15598	17090	17000	17150	Revenues ($mill)	19850
904.0	1005.0	1020.0	1198.0	1168.0	1113.0	1132.0	893.0	828.0	1450.0	945	1605	Net Profit ($mill)	2275
37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	19.2%	20.0%	25.0%	Income Tax Rate	26.5%
5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	10.0%	16.0%	9.0%	AFUDC % to Net Profit	7.0%
48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.5%	49.5%	50.0%	Long-Term Debt Ratio	48.0%
50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	50.7%	49.5%	49.0%	Common Equity Ratio	51.5%
14446	16696	18558	20163	21793	22863	24119	25956	27311	31050	33100	36325	Total Capital ($mill)	42300
19955	21785	23656	26261	28892	31449	33655	37523	41252	43941	46400	49075	Net Plant ($mill)	57300
8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	5.8%	4.0%	5.5%	Return on Total Cap'l	6.5%
12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.1%	5.5%	9.0%	Return on Shr. Equity	10.5%
12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.1%	5.5%	9.0%	Return on Com Equity E	10.5%
7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	3.9%	.5%	4.0%	Retained to Com Eq	5.0%
39%	47%	50%	47%	52%	61%	63%	85%	96%	58%	95%	57%	All Div'ds to Net Prof	51%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+6.0	+.5	-.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.17	9.28	9.98
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.5	+.3	+.6
Fixed Charge Cov. (%)	231	223	304

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	2.0%	-1.5%	1.5%
"Cash Flow"	6.5%	-2.5%	7.0%
Earnings	14.5%	-5.0%	10.5%
Dividends	--	3.0%	3.0%
Book Value	9.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3641	3593	3976	3830	15040
2013	3672	3776	4175	3975	15598
2014	3891	3952	4939	4308	17090
2015	3899	4217	4550	4334	17000
2016	4000	4250	4550	4350	17150

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.66	.55	.87	d.01	2.07
2013	.55	.74	.36	.19	1.83
2014	.49	.57	1.71	.27	3.06
2015	.27	.83	.63	.17	1.90
2016	.70	.80	1.05	.60	3.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.455	.455	.455	.455	1.82
2013	.455	.455	.455	.455	1.82
2014	.455	.455	.455	.455	1.82
2015	.455	.455	.455	.455	1.82
2016	.455				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.3 million electric and 4.4 million gas customers. Electric revenue breakdown: residential, 38%; commercial, 40%; industrial, 12%; agricultural, 9%; other, 1%. Generating sources: nuclear, 21%; hydro, 8%; gas, 7%; purchased, 64%. Fuel costs: 38% of revenues. '14 reported depreciation rate (utility): 3.8%. Has 22,600 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. Telephone: 415-973-1000. Internet: www.pgecorp.com.

PG&E has a general rate case pending. The utility filed for rate hikes of $457 million in 2017, $489 million in 2018, and $390 million in 2019. PG&E is asking the California Public Utilities Commission (CPUC) for a ruling by yearend. Even if the CPUC's decision slips into next year, it will be retroactive to the start of 2017.

The utility is still awaiting an order on its gas transportation and storage case. PG&E filed for rate increases of $532 million in 2015, $83 million in 2016, and $142 million in 2017. However, part of whatever increase the company is granted will be reduced as a result of penalties for a gas pipeline explosion in San Bruno, California in 2010. (The accident killed eight people, injured many more, and caused extensive property damage.) The utility will face an additional penalty in this proceeding as a result of *ex parte* communications between former company employees and a former CPUC president. PG&E is facing a federal lawsuit stemming from the San Bruno accident, and the CPUC is investigating the utility's safety culture.

The costs and penalties associated with San Bruno have hurt earnings in recent years. Except for $300 million in fines, which we have excluded from our earnings presentation as nonrecurring, we have *included* any costs (as well as any insurance recoveries) associated with the accident and the remedial measures that PG&E took subsequently. These expenses probably lowered earnings by more than $1.00 a share in 2015. We figure that the negative effect won't be nearly as high this year. The uncertainty about the amount and timing of these charges makes PG&E's profits more unpredictable than its Earnings Predictability Index suggests.

Will the board of directors raise the dividend this year? Understandably, the disbursement has been held flat since the San Bruno accident. We aren't estimating a dividend boost until next year, but wouldn't rule one out in 2016.

We do not recommend this stock. In our view, the dividend yield isn't high enough to compensate investors for the regulatory and legal uncertainty the company faces. Total return potential to 2018-2020 is unspectacular, too.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, ($2.44); '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); 1Q '15, (21¢); gain from disc. ops.: '08, 41¢. '13 EPS don't add due to rounding, '14 due to change in shs. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '14: $13.28/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '14: 9.5%. Regulatory Climate: Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	60

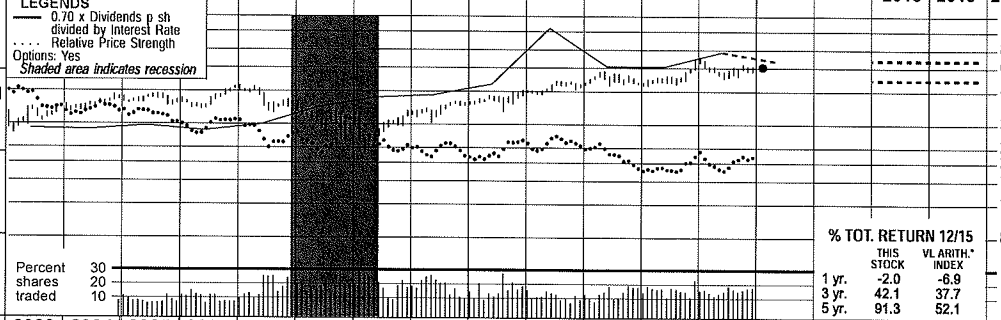
PINNACLE WEST NYSE-PNW

RECENT PRICE 64.88 | P/E RATIO 16.4 (Trailing: 18.1 / Median: 15.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 10/16/15
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Lowered 12/25/15
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low:	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	6%
Low	55	(-15%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	13	0
to Sell	1	0	0	1	0	0	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	182	175	181
to Sell	194	180	175
Hld's(000)	86769	87394	89339

Percent shares traded 30 20 10

Target Price Range 2018 | 2019 | 2020

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.0	-6.9
3 yr.	42.1	37.7
5 yr.	91.3	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	*31.55*	*32.75*	Revenues per sh	*36.50*
7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	*8.85*	*9.35*	"Cash Flow" per sh	*10.50*
3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	*3.75*	*4.00*	Earnings per sh A	*4.50*
1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	*2.56*	Div'd Decl'd per sh B ■	*2.95*
4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	*9.90*	*10.40*	Cap'l Spending per sh	*9.75*
26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	*40.85*	*42.25*	Book Value per sh C	*47.00*
84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	*111.00*	*111.50*	Common Shs Outst'g D	*118.00*
11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	*16.8*		Avg Ann'l P/E Ratio	*13.5*
.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	*.85*		Relative P/E Ratio	*.85*
3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3725.8 mill. **Due in 5 Yrs** $1486.6 mill.
LT Debt $3257.3 mill. **LT Interest** $159.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/14 $2615.4 mill. **Oblig.** $3078.7 mill.
Pfd Stock None

Common Stock 110,849,752 shs. as of 10/23/15
MARKET CAP: $7.2 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	*3500*	*3650*	Revenues ($mill)	*4300*
223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	*420*	*445*	Net Profit ($mill)	*535*
36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	*35.0%*	*34.5%*	Income Tax Rate	*34.5%*
10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*45.5%*
56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	*55.5%*	*53.5%*	Common Equity Ratio	*54.5%*
6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	*8165*	*8765*	Total Capital ($mill)	*10175*
7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	*11725*	*12300*	Net Plant ($mill)	*14075*
5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	*65%*	*64%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.2	-.2	-1.8
Avg. Indust. Use (MWH)	647	644	659
Avg. Indust. Revs. per KWH (¢)	7.86	8.21	8.26
Capacity at Peak (Mw)	8864	8398	9259
Peak Load, Summer (Mw)	7207	6927	7007
Annual Load Factor (%)	48.8	50.0	48.6
% Change Customers (yr-end)	+1.3	+1.4	+1.2
Fixed Charge Cov. (%)	397	419	404

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-1.5%	*3.0%*
"Cash Flow"	1.5%	-1.0%	*4.5%*
Earnings	3.5%	8.0%	*4.0%*
Dividends	3.5%	3.0%	*3.5%*
Book Value	2.0%	2.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.6	1199.1	*739.1*	*3500*
2016	*700*	*975*	*1225*	*750*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	*.21*	*3.75*
2016	*.15*	*1.30*	*2.35*	*.20*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595	.595	.625	2.41
2016					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 48%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 34%; nuclear, 27%; gas & other, 17%; purchased, 22%. Fuel costs: 34% of revenues. Has 6,400 employees. '14 reported deprec. rate: 2.8%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is trying to address the issue of rate design with the Arizona Corporation Commission (ACC). Currently, about 70% of Arizona Public Service's costs of serving residential customers are fixed, but only 10% of its revenues are derived from fixed charges on customers' bills. In addition, because of the way rates are designed, nonsolar customers are subsidizing those users with rooftop solar panels. This is an industrywide problem, and APS is by no means the only utility that is concerned about this. Accordingly, the ACC is conducting hearings with APS and other utilities in the state. Not surprisingly, this has been a highly politicized question. APS will probably file a rate application at the start of June. This case will address the rate design concerns, including information gathered from the current proceedings, as well as seeking some (probably modest) rate relief. New rates (and rate design) would take effect in mid-2017.

The utility will probably begin construction of a gas-fired plant soon. The 510-megawatt facility would cost an estimated $500 million. APS would replace 290 mw of older generating capacity, thereby providing a net increase of 220 mw. This project is expected to be completed in 2019.

We look for a respectable profit increase in 2016. Every year, APS benefits from regulatory mechanisms that provide some revenue — most notably for electric transmission and a portion of the utility's lost revenues that come as a result of conservation measures. Also, the utility is seeing respectable customer growth in its service territory, along with a small amount of sales growth. Our 2016 earnings estimate is within the company's targeted range of $3.90-$4.10 a share.

Finances are strong. The fixed-charge coverage and common-equity ratio are comfortably above the industry averages. Pinnacle West merits a Financial Strength rating of A+.

This top-quality stock offers a dividend yield that is about equal to the utility mean. With the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $12.30/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.

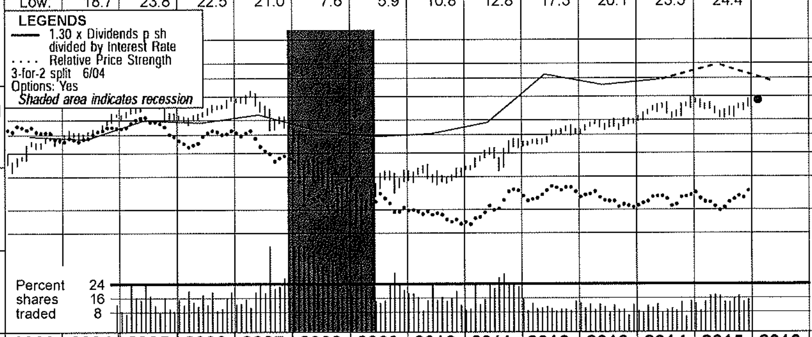
Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

PNM RESOURCES NYSE-PNM

RECENT PRICE **30.55** | P/E RATIO **19.1** (Trailing: 18.5 Median: 17.0) | RELATIVE P/E RATIO **1.16** | DIV'D YLD **2.9%** | VALUE LINE

TIMELINESS **3** Lowered 6/19/15
SAFETY **3** Lowered 5/9/08
TECHNICAL **3** Raised 1/29/16
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2
Low:	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	12%
Low	30	(Nil)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	0	0	0	0	0	1
Options	4	0	0	0	0	0	0	0	0
to Sell	4	0	0	0	0	0	0	0	3

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	108	116	99
to Sell	110	104	108
Hld's(000)	69125	69968	71254

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	-6.9
3 yr.	62.2	37.7
5 yr.	171.5	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	*18.15*	*18.75*	Revenues per sh	*20.30*
2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	*3.70*	*3.85*	"Cash Flow" per sh	*4.70*
1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	*1.60*	*1.65*	Earnings per sh A	*2.35*
.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	*.88*	Div'd Decl'd per sh B ■†	*1.30*
1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	*5.50*	*5.50*	Cap'l Spending per sh	*5.50*
14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	*22.10*	*22.70*	Book Value per sh C	*25.50*
61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	*17.3*		Avg Ann'l P/E Ratio	*16.0*
.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	*.88*		Relative P/E Ratio	*1.00*
4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2208.0 mill. **Due in 5 Yrs** $1112 mill.
LT Debt $1980.4 mill. **LT Interest** $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/14 $657.6 mill. **Oblig.** $587.7 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs. **as of 10/23/15**
MARKET CAP: $2.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	*1450*	*1500*	Revenues ($mill)	*1625*
106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	*130*	*135*	Net Profit ($mill)	*190*
31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	*1.5%*	*2.5%*	AFUDC % to Net Profit	*8.0%*
57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	*52.0%*	*53.0%*	Long-Term Debt Ratio	*53.5%*
42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	*48.0%*	*47.0%*	Common Equity Ratio	*46.5%*
3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	*3695*	*3845*	Total Capital ($mill)	*4385*
2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	*4335*	*4555*	Net Plant ($mill)	*5270*
4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	*7.0%*	*7.5%*	Return on Shr. Equity	*9.5%*
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	*7.0%*	*7.5%*	Return on Com Equity E	*9.5%*
4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
48%	49%	117%	NMF	86%	58%	47%	43%	45%	51%	*51%*	*51%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICSF

	2012	2013	2014
% Change Retail Sales (KWH)	-1.6	-2.9	-2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2537	2572	2707
Peak Load, Summer (Mw)	1948	2008	1948
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.7	+.6
Fixed Charge Cov. (%)	225	241	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-3.0%	-4.5%	*1.5%*
"Cash Flow"	1.5%	9.5%	*5.0%*
Earnings	1.5%	23.5%	*9.0%*
Dividends	1.0%	--	*10.0%*
Book Value	2.0%	1.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	*346.8*	*1450*
2016	*345*	*360*	*440*	*355*	*1500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	*.19*	*1.60*
2016	*.25*	*.40*	*.75*	*.25*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '14: residential, 37%; commercial, 37%; industrial, 6%; other, 20%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '14 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources recently got the go-ahead from state regulators to move forward with its clean power plan. Indeed, the New Mexico Public Regulatory Commission in mid-December formally approved the utility's proposed shutdown of two coal-fired units at the San Juan Generating Station (SJGS) in the northern part of the state by the end of 2017. Meantime, the remaining (two) SJGS coal units were recently retrofitted with new emission controls, while other facilities, including a 40-megawatt solar installation, are now slated to fill the breach. Part of a broader effort to meet clean-air mandates, the moves recently needed additional approvals to proceed.

The utility recently said that it expects to earn between $1.55 and $1.76 a share in 2016. Based on a company-issued 2015 baseline ($1.56-$1.61), the target range implies as much as 13% bottom-line growth down to a modest (less than 4%) decline this year. The wide variance largely reflects the uncertain timing of a rate hike by PNM's Public Service of New Mexico (PNM) unit. Notably, a three-month implementation delay (October 1st versus July 1st) could nick earnings by 12%, or $0.21 a share.

Stretch goals include 7%-9% earnings growth through 2019. Key to reaching the mark will be PNM's ability to earn authorized returns on its regulated businesses, which isn't a given. Among additional concerns is a New Mexico economy that is highly dependent on public works projects and which has been growing at a slow pace compared to the nation as a whole.

The board of directors recently authorized a 10% dividend hike. The higher quarterly distribution ($0.22 a share) will first be paid on February 12th, to shareholders of record on January 25th. On an annualized basis, it represents a serviceable 50%-64% of PNM's targeted 2016 earnings.

Shares of PNM Resources are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. Recent dividend hikes are encouraging, but more-competitive yields can be found elsewhere.

Nils C. Van Liew *January 29, 2016*

(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '14: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	35

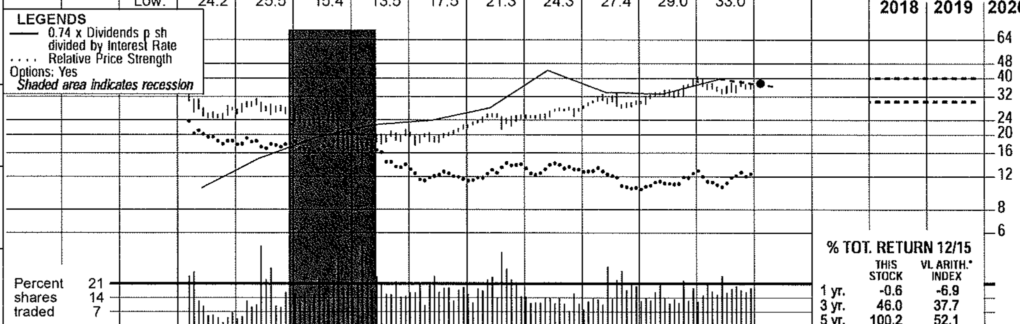
PORTLAND GENERAL NYSE-POR

RECENT PRICE 37.69 | P/E RATIO 16.8 (Trailing: 18.8 Median: NMF) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 8/14/15
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Lowered 12/4/15
BETA .80 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+5%)	5%
Low	30	(-20%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	1	0	0	0	2	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	122	112	113
to Sell	142	136	110
Hld's(000)	84710	86966	86675

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.6	-6.9
3 yr.	46.0	37.7
5 yr.	100.2	52.1

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2005[G]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.10	22.45	Revenues per sh	24.25
4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.40	5.90	"Cash Flow" per sh	7.00
1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.05	2.35	Earnings per sh A	2.75
--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	Div'd Decl'd per sh B ■ †	1.50
4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.80	5.00	Cap'l Spending per sh	3.25
19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.40	26.45	Book Value per sh C	29.75
62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.90	89.10	Common Shs Outst'g D	89.70
--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.6		Avg Ann'l P/E Ratio	12.5
--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.90		Relative P/E Ratio	.80
--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	4.4%
1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1875	2000	Revenues ($mill)	2175
64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	175	210	Net Profit ($mill)	245
40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	21.5%	21.5%	Income Tax Rate	21.5%
18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	15.0%	7.0%	AFUDC % to Net Profit	3.0%
42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	49.5%	49.5%	Long-Term Debt Ratio	49.5%
57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	50.5%	50.5%	Common Equity Ratio	50.5%
2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4460	4675	Total Capital ($mill)	5325
2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	5980	6110	Net Plant ($mill)	6025
4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.0%	5.5%	Return on Total Cap'l	6.0%
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.5%	9.0%	Return on Shr. Equity	9.0%
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.5%	9.0%	Return on Com Equity E	9.0%
5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.5%	4.5%	Retained to Com Eq	4.0%
--	39%	40%	69%	76%	62%	54%	57%	61%	50%	56%	53%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2204 mill. **Due in 5 Yrs** $510 mill.
LT Debt $2204 mill. **LT Interest** $115 mill.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/14 $591 mill. **Oblig.** $777 mill.

Pfd Stock None

Common Stock 88,772,420 shs.
as of 10/16/15

MARKET CAP: $3.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.8	+1.2	-.8
Avg. Indust. Use (MWH)	16409	16258	16577
Avg. Indust. Revs. per KWH (¢)	5.26	4.84	5.13
Capacity at Peak (Mw)	4173	4380	4910
Peak Load, Winter (Mw) F	3597	3869	3866
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.9	+.7
Fixed Charge Cov. (%)	270	239	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-2.0%	.5%
"Cash Flow"	--	3.0%	4.5%
Earnings	--	3.0%	6.0%
Dividends	--	2.5%	5.5%
Book Value	--	2.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.0	413.0	450.0	463.0	1805.0
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	450.0	476.0	476	1875
2016	525	460	505	510	2000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	.59	2.05
2016	.80	.45	.45	.65	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 852,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 12%; other, 7%. Generating sources: coal, 21%; gas, 16%; hydro, 8%; wind, 6%; purchased, 49%. Fuel costs: 38% of revenues. '14 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

The Oregon Public Utility Commission has approved a regulatory settlement for Portland General Electric. At the start of 2016, PGE's rates were *lowered* by $15 million. The reduction reflects, in part, lower net variable power costs that are being passed through to ratepayers. Then, when the Carty gas-fired generating plant begins commercial operation (as long as this is no later than July 31st), the utility's rates would rise by $85 million. The allowed return on equity is 9.6%, and the new rates reflect a common-equity ratio of 50%. However . . .

The Carty plant has run into a construction problem. Initially, the 440-megawatt facility was expected to enter service in the second quarter of 2016 at a cost of $514 million. But the company that was building the plant went bankrupt and ceased construction. PGE took control of the site, and construction has resumed, although it took some time for it to ramp back up. What effect this will have on the cost and timing of the project is unknown. Management plans to provide an update when the utility reports earnings in mid-February.

We still expect a significant profit increase in 2016. Once Carty begins commercial operation, PGE will benefit from the associated rate relief. (At this point, we are not assuming that the delay will have a major effect on the utility's income.) Also, a year ago PGE's service area experienced its warmest winter on record. This made the first-quarter comparison easy. The utility is benefiting from growth in its service area's economy.

Is this company a takeover candidate? With increased merger and acquisition activity in the electric utility industry, PGE is considered in some circles as a prospective acquiree. However, investors should be aware that, more than 10 years ago, a proposed buyout of the company fell through. Thus, we do not advise purchase of this issue in the hope of a buyout.

This stock's dividend yield is slightly below the industry average. Although we project respectable dividend growth over the 3- to 5-year time frame, with the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: $6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	70

SCANA CORP. NYSE-SCG

RECENT PRICE 59.63 | P/E RATIO 15.4 (Trailing: 15.5 Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 11/13/15
SAFETY 2 Lowered 9/10/99
TECHNICAL 2 Raised 11/20/15
BETA .75 (1.00 = Market)

High:	39.7	43.7	42.4	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6			
Low:	32.8	36.6	36.9	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	49.9			

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

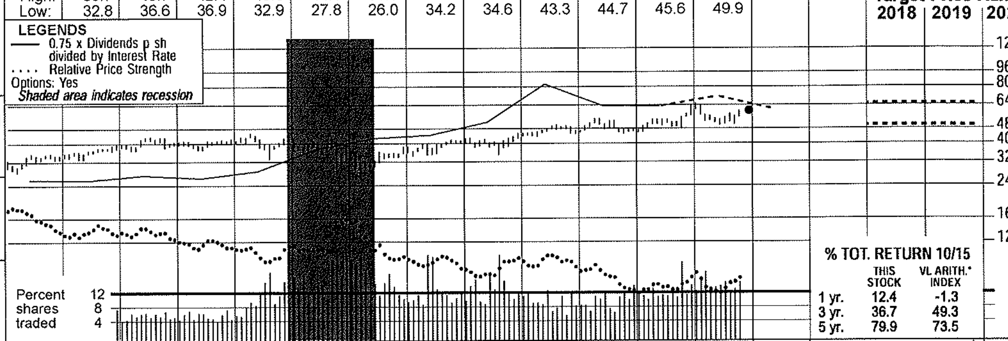
	Price	Gain	Ann'l Total Return
High	65	(+10%)	6%
Low	50	(-15%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	194	186	197
to Sell	172	199	181
Hld's(000)	81369	82049	82455



% TOT. RETURN 10/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.4	-1.3
3 yr.	36.7	49.3
5 yr.	79.9	73.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
15.93	32.78	32.95	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.70	*31.80*	*33.20*	Revenues per sh	*37.00*
3.15	4.43	4.55	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	6.91	*7.15*	*7.15*	"Cash Flow" per sh	*8.25*
1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.79	*3.85*	*3.95*	Earnings per sh A	*4.50*
1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	*2.18*	*2.26*	Div'd Decl'd per sh B ■	*2.50*
2.37	3.28	4.99	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	7.65	*10.95*	*13.40*	Cap'l Spending per sh	*8.75*
20.27	19.40	20.95	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	*38.10*	*39.85*	Book Value per sh C	*46.50*
103.57	104.73	104.73	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	142.70	*143.00*	*143.00*	Common Shs Outst'g D	*149.00*
17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.72	*Value Line*		Relative P/E Ratio	*.80*
5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $6307 mill. **Due in 5 Yrs** $1154 mill.
LT Debt $6018 mill. **LT Interest** $285 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $8 mill.
Pension Assets-12/14 $861.8 mill.
Oblig. $919.5 mill.
Pfd Stock None

Common Stock 142,916,917 shs.
as of 7/31/15
MARKET CAP: $8.5 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
4777.0	4563.0	4621.0	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4951.0	*4550*	*4750*	Revenues ($mill)	*5500*
323.0	306.0	327.0	353.0	357.0	376.0	387.0	420.0	471.0	538.0	*555*	*575*	Net Profit ($mill)	*675*
--	26.5%	29.2%	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	31.6%	*32.0%*	*32.0%*	Income Tax Rate	*33.5%*
.9%	2.6%	4.6%	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.1%	*7.0%*	*16.0%*	AFUDC % to Net Profit	*3.0%*
51.4%	50.9%	48.4%	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	52.6%	*52.0%*	*55.0%*	Long-Term Debt Ratio	*54.0%*
46.6%	47.2%	49.7%	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	47.4%	*48.0%*	*45.0%*	Common Equity Ratio	*46.0%*
5739.0	6027.0	5952.0	7519.0	7891.0	7854.0	8511.0	9103.0	10059	10518	*11325*	*12675*	Total Capital ($mill)	*15050*
6734.0	7007.0	7538.0	8305.0	9009.0	9662.0	10047	10896	11643	12232	*12975*	*14450*	Net Plant ($mill)	*17325*
7.4%	6.8%	7.3%	6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.6%	10.3%	10.6%	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	10.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
11.8%	10.5%	10.8%	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	10.8%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
5.3%	3.8%	4.0%	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	4.9%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
56%	65%	64%	62%	66%	63%	64%	61%	60%	55%	*56%*	*56%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.9	+.3	+4.7
Avg. Indust. Use (MWH)	8055	8180	NA
Avg. Indust. Revs. per KWH (¢)	7.09	7.27	NA
Capacity at Yearend (Mw)	5533	5237	5237
Peak Load, Summer (Mw)	4761	4574	4853
Annual Load Factor (%)	56.8	58.8	NA
% Change Customers (yr-end)	+.9	+1.2	+1.4
Fixed Charge Cov. (%)	281	293	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-4.0%	*2.0%*
"Cash Flow"	3.0%	3.0%	*4.0%*
Earnings	3.0%	4.0%	*4.5%*
Dividends	4.0%	2.0%	*3.5%*
Book Value	5.0%	5.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1107	908	1038	1123	4176.0
2013	1311	1016	1051	1117	4495.0
2014	1590	1026	1121	1214	4951.0
2015	1389	967	1068	*1126*	*4550*
2016	*1425*	*1025*	*1075*	*1225*	*4750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.91	.54	.91	.78	3.15
2013	1.11	.60	.94	.73	3.39
2014	1.37	.68	1.01	.73	3.79
2015	1.39	.69	1.04	*.73*	*3.85*
2016	*1.40*	*.70*	*1.10*	*.75*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.475	.485	.485	.485	1.93
2012	.485	.495	.495	.495	1.97
2013	.495	.507	.507	.507	2.02
2014	.508	.525	.525	.525	2.08
2015	.525	.545	.545	.545	

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 697,000 customers in South Carolina. Supplies gas and transmission service to 1.3 million customers in North and South Carolina and Georgia. Acquired PSNC Energy 2/00. Electric revenue breakdown: residential, 44%; commercial, 33%; industrial, 18%; other, 5%. Generating sources: coal, 48%; oil & gas, 28%; nuclear, 19%; hydro, 3%; purchased, 2%. Fuel costs: 53% of revenues. '14 reported depreciation rate: 2.8%. Has 5,900 employees. Chairman, CEO & President: Kevin B. Marsh. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA's electric utility subsidiary has amended its agreement with contractors for the two nuclear units it is building. The units are still expected to come on line in 2019 and 2020, but in August of each year instead of June. The revised agreement calls for South Carolina Electric & Gas to pay an additional $286 million, raising the current estimate of its 55% stake in the project to $7.1 billion. The utility also obtained an option (through November 1, 2016) to convert the contract to a fixed price of $7.6 billion, which would make the new contractor, Westinghouse, responsible for any overruns. The South Carolina regulators would still have to approve recovery of any amount above the currently authorized $6.8 billion, which the commission approved in September.

SCE&G was granted its annual increase under the state's Base Load Review Act. Each year, the utility receives rate relief under this law in order to recover construction work in progress for the aforementioned nuclear units. This contributes to the company's earnings growth. Electric rates were raised by $64.5 million (2.6%) in late October. This and previous increases were based on an 11.0% return on equity, but beginning next year, the allowed ROE will drop to 10.5%.

We have raised our 2015 earnings estimate by $0.05 a share. Third-quarter profits were better than we had expected due to favorable weather patterns. Our revised estimate of $3.85 is above the company's targeted range of $3.60-$3.80 because SCANA bases its guidance on normal weather conditions.

We forecast a modest bottom-line increase in 2016. We assume normal weather conditions, compared with the favorable ones that have helped lift earnings in 2015. Our estimate of $3.95 a share is within SCANA's guidance of $3.90-$4.10.

Public Service of North Carolina might file a rate case next year. The utility is earning an ROE well below the authorized 10.6%. New rates wouldn't help earnings until 2017, however.

This untimely stock's yield is average for a utility. The recent price is above the midpoint of our 2018-2020 Target Price Range, so total return potential is low.

Paul E. Debbas, CFA *November 20, 2015*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢; '15, $1.41. '12 & '13 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '14: $12.78/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 10.6% in '08; earned on avg. com. eq., '14: 11.1%. Regulatory Climate: Above Average.

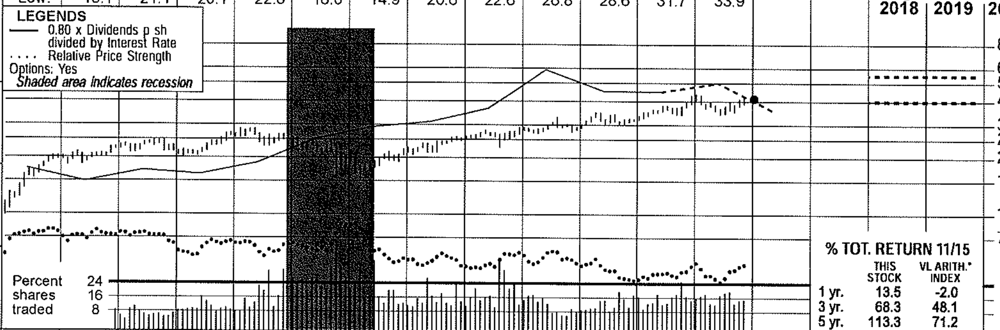
Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

WESTAR ENERGY NYSE-WR

RECENT PRICE 41.40 | P/E RATIO 17.5 (Trailing: 19.3 Median: 14.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 2 Raised 12/18/15
BETA .75 (1.00 = Market)

High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	0	1	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	134	146	137
to Sell	155	125	121
Hld's(000)	97474	97324	99969

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	-2.0
3 yr.	68.3	48.1
5 yr.	113.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*18.45*	*18.60*	Revenues per sh	*18.70*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.40*	*4.75*	"Cash Flow" per sh	*5.45*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.25*	*2.45*	Earnings per sh A	*3.10*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.70*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*6.50*	*7.00*	Cap'l Spending per sh	*7.95*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.25*	*26.75*	Book Value per sh C	*28.55*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*140.00*	*145.00*	Common Shs Outst'g E	*155.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	*Value Line*		Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3245.5 mill. **Due in 5 Yrs** $1000 mill.
LT Debt $2941.9 mill. **LT Interest** $120.0 mill.
(LT interest earned: 2.7x)

Pension Assets 12/14 $661 mill. **Oblig.** $914 mill.

Pfd Stock None

Common Stock 141,838,178 shs.
MARKET CAP: $5.9 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2700*	Revenues ($mill)	*2900*
134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*315*	*355*	Net Profit ($mill)	*480*
31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8600*	Net Plant ($mill)	*9000*
6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*64%*	*61%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	2.5%
"Cash Flow"	1.5%	5.0%	4.5%
Earnings	6.5%	9.0%	6.0%
Dividends	3.5%	3.5%	3.0%
Book Value	5.0%	3.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	732.8	*666.8*	*2580*
2016	*645*	*630*	*775*	*650*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	.97	*.44*	*2.25*
2016	*.50*	*.45*	*1.10*	*.40*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 41%; commercial, 38%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2014 depreciation rate: 3.9%. Estimated plant age: 16 years. Fuels: coal, 48%; nuclear, 8%; gas, 44%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Regulators approved a $78 million rate hike for Westar Energy. The Kansas Corporation Commission accepted a 4%, or $78 million, rate increase that should help cover some of the utility's costs associated with upgrading several power plants. Westar Energy originally sought a $152 million boost, but subsequently dropped that demand to $78 million after failing to garner enough support from lawmakers. Utilities routinely ask for relatively large rate increases that often get negotiated down by legislators, so the outcome was not at all unexpected.

Much of the new revenue will cover the cost of upgrades at the La Cygne Energy Center and Wolf Creek. Improvements at La Cygne were required by federal air pollution standards. The facility received a baghouse, wet scrubber, and selective catalytic reduction (SCR) to reduce emissions. At Wolf Creek, the upgrades were tied to a decision to keep the plant in operation for 20 years longer than initially planned, until 2045.

Westar continues to modernize electricity production. The company announced plans to phase out by yearend old electrical-generating equipment at three locations. That should help reduce carbon emissions and energy waste, while also lowering operational costs at several plants. Furthermore, management will add more renewable energy production in the coming months as this appears to be a reasonable alternative to investing in more electrical-generating equipment.

We look for a dividend hike at the upcoming board meeting. The increase will likely add a penny to the quarterly distribution, in line with the pattern in recent years. Also, Westar Energy is targeting a payout ratio of 50%-60%, so we expect only moderate dividend growth potential through the 3- to 5-year period.

This stock provides a steady source of income for conservative investors. The yield is around the average for electric utilities, and the payout has been raised every year since 2003. In addition, we expect cost-control measures and higher rates to drive above-average earnings growth over the next few years. That should allow Westar to increase the dividend uninterrupted.

Daniel Henigson *December 18, 2015*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early February. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

XCEL ENERGY NYSE-XEL

RECENT PRICE 37.21 | P/E RATIO 16.9 (Trailing: 17.9 / Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 2 Raised 12/25/15
SAFETY 1 Raised 5/1/15
TECHNICAL 3 Lowered 12/25/15
BETA .65 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3
Low:	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

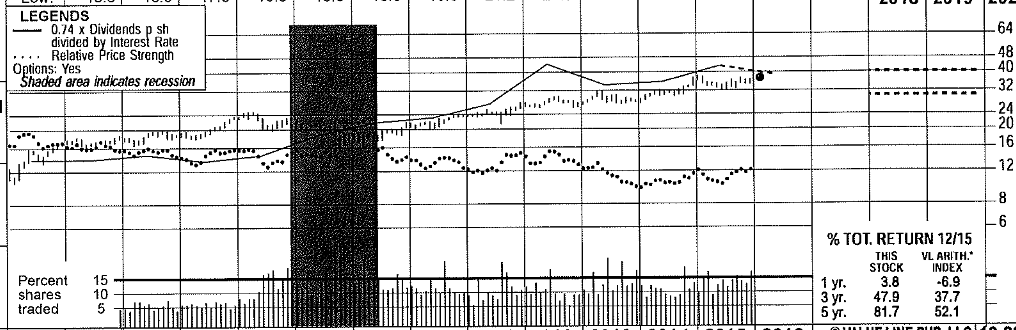
	Price	Gain	Ann'l Total Return
High	40	(+5%)	6%
Low	30	(-20%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	214	217	229
to Sell	255	242	221
Hld's(000)	351734	355032	358878



% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.8	-6.9
3 yr.	47.9	37.7
5 yr.	81.7	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.85	22.65	Revenues per sh	25.00
4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.60	4.85	"Cash Flow" per sh	5.50
1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.20	Earnings per sh A	2.50
1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	Div'd Decl'd per sh B ■ †	1.60
13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	6.65	6.00	Cap'l Spending per sh	6.00
16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.90	21.75	Book Value per sh C	24.50
155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	508.00	508.00	Common Shs Outst'g D	508.00
16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5		Avg Ann'l P/E Ratio	14.0
.95	.93	.64	NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.85		Relative P/E Ratio	.90
6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $13212 mill. **Due in 5 Yrs** $2977.7 mill.
LT Debt $12691 mill. **LT Interest** $599.0 mill.
Incl. $172.2 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $254.5 mill.
Pension Assets-12/14 $3083.8 mill.
Oblig. $3476.7 mill.
Pfd Stock None

Common Stock 507,496,978 shs.
as of 10/26/15
MARKET CAP: $19 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
9625.5	9840.3	10034	11203	9644.3	10311	10655	10128	10915	11686	11100	11500	Revenues ($mill)	12700
499.0	568.7	575.9	645.7	685.5	727.0	841.4	905.2	948.2	1021.3	1055	1125	Net Profit ($mill)	1285
25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.0%	35.0%	Income Tax Rate	35.0%
8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	8.0%	7.0%	AFUDC % to Net Profit	6.0%
51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.0%	54.5%	Long-Term Debt Ratio	52.0%
47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	46.0%	45.5%	Common Equity Ratio	48.0%
11398	12371	12748	14800	15277	17452	17331	19018	20477	21714	23125	24200	Total Capital ($mill)	25800
14696	15549	16676	17689	18508	20663	22353	23809	26122	28757	30850	32250	Net Plant ($mill)	37200
6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	6.0%	6.0%	Return on Total Cap'l	6.5%
9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.0%	Return on Shr. Equity	10.5%
9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.0%	Return on Com Equity E	10.5%
2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.0%	4.0%	Retained to Com Eq	4.0%
69%	63%	66%	59%	61%	59%	56%	54%	54%	55%	61%	61%	All Div'ds to Net Prof	63%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.3	+.3	+.2
Large C & I Use (MWH)	24074	23875	24475
Large C & I Revs. per KWH (¢)	5.60	6.23	6.47
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21429	21258	21429
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.9
Fixed Charge Cov. (%)	303	321	344

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-1.0%	2.0%
"Cash Flow"	2.5%	3.5%	5.0%
Earnings	7.0%	6.0%	4.5%
Dividends	2.5%	3.5%	6.0%
Book Value	4.5%	4.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	2578	2275	2724	2551	10128
2013	2783	2579	2822	2731	10915
2014	3203	2685	2870	2928	11686
2015	2962	2515	2901	2722	11100
2016	3100	2600	3000	2800	11500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.38	.38	.81	.29	1.85
2013	.48	.40	.73	.30	1.91
2014	.52	.39	.73	.39	2.03
2015	.46	.39	.84	.41	2.10
2016	.53	.42	.85	.40	2.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.26	.26	.27	.27	1.06
2013	.27	.27	.28	.28	1.10
2014	.28	.30	.30	.30	1.18
2015	.30	.32	.32	.32	1.26
2016	.32				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.5 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 32%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 19%; other, 13%. Generating sources not available. Fuel costs: 49% of revs. '14 reported depr. rate: 2.7%. Has 11,700 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility subsidiary in Minnesota has filed a multiyear electric rate case. Northern States Power (NSP) is seeking tariff increases of $194.6 million (6.4%) in 2016, $52.1 million (1.7%) in 2017, and $50.4 million (1.7%) in 2018, based on return of 10% on a common-equity ratio of 52.5%. NSP was granted an interim increase of $163.7 million at the start of 2016. A final decision is expected in the first quarter of 2017.

By filing a multiyear application, the utility hopes to reduce the effects of regulatory lag. Currently, Xcel's utility subsidiaries (as a group) are earning a return on equity that is about a percentage point below their allowed ROE. Public Service of Colorado has a multiyear gas rate case pending, in which it should soon receive a decision. Eventually, Xcel wants to derive 75% of its revenues from multiyear plans. By the end of the current quarter, Southwestern Public Service (SPS) plans to ask the Texas regulators for an electric rate boost—the utility's first case under a new law that reduced regulatory lag in the state from one year to seven months. Xcel is aiming to improve its earned ROE by a half percentage point by 2018, and by even more beyond then.

Other rate cases have been completed or are pending. In Texas, SPS received a rate hike of $42.1 million, based on a 9.7% ROE. In Wisconsin, NSP was granted electric and gas increases of $7.6 million and $4.2 million, respectively, based on a 10% ROE. In New Mexico, SPS is seeking a $45.4 million raise, based on a 10.25% return on a 54% common-equity ratio. A ruling is expected in the second half of 2016.

Rate relief is enabling Xcel's earnings to advance gradually. The company is targeting 4%-6% annual profit growth. Our 2016 estimate is within management's guidance of $2.12-$2.27 a share. If Xcel is able to raise its earned ROE by a half percentage point, this would add $0.12 a share to annual earnings.

Timely and high-quality Xcel stock has an average valuation for a utility. The dividend yield is about average for the group. Like many utility issues, the recent quotation is within our 2018-2020 Target Price Range. Accordingly, 3- to 5-year total return potential is unimpressive.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '02, ($6.27); '10, 5¢; '15, (16¢); gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '12 EPS don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intang. In '14: $5.49/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.8%; earned on avg. com. eq., '14: 10.3%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

Summary of Risk Premium Models for the
Proxy Group of Eighteen Electric Companies

	Proxy Group of Eighteen Electric Companies
Predictive Risk Premium Model ™ (PRPM™) (1)	10.77 %
Risk Premium Using an Adjusted Total Market Approach (2)	10.25 %
Average	10.51 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

Proxy Group of Eighteen Electric Companies
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

Proxy Group of Eighteen Electric Companies	[1] LT Average Predicted Variance	[2] Spot Predicted Variance	[3] Average Predicted Variance	[4] GARCH Coefficient	[5] Predicted Risk Premium (2)	[6] Risk-Free Rate (3)	[7] Indicated ROE (4)
ALLETE, Inc.	0.29%	0.23%	0.26%	2.12549	6.84%	3.68%	10.52%
Alliant Energy Corp.	0.27%	0.22%	0.25%	2.45671	7.62%	3.68%	11.30%
Ameren Corp.	0.23%	0.19%	0.21%	1.68373	4.33%	3.68%	8.01%
American Electric Power Co., Inc.	0.29%	0.21%	0.25%	2.30894	7.15%	3.68%	10.83%
Consolidated Edison, Inc.	0.47%	0.28%	0.38%	1.52454	7.18%	3.68%	10.86%
Edison International	0.43%	0.29%	0.36%	1.58248	7.05%	3.68%	10.73%
El Paso Electric Company	0.40%	0.21%	0.31%	1.86919	7.18%	3.68%	10.86%
Great Plains Energy, Inc.	0.29%	0.24%	0.27%	2.31205	7.75%	3.68%	11.43%
IDACORP, Inc.	0.29%	0.28%	0.29%	2.13923	7.70%	3.68%	11.38%
OGE Energy Corp.	0.31%	0.31%	0.31%	2.11723	8.17%	3.68%	11.85%
Otter Tail Corp.	0.39%	0.22%	0.30%	1.46301	5.40%	3.68%	9.08%
PG&E Corp.	0.41%	0.27%	0.34%	1.85858	7.85%	3.68%	11.53%
Pinnacle West Capital Corp.	0.62%	0.24%	0.43%	1.21767	6.47%	3.68%	10.15%
PNM Resources, Inc.	0.55%	0.38%	0.46%	1.21281	6.90%	3.68%	10.58%
Portland General Electric Co.	0.28%	0.17%	0.22%	1.79479	4.84%	3.68%	8.52%
SCANA Corp.	0.31%	0.23%	0.27%	2.44089	8.20%	3.68%	11.88%
Westar Energy, Inc.	0.27%	0.27%	0.27%	2.35255	7.89%	3.68%	11.57%
Xcel Energy Inc.	0.28%	0.16%	0.22%	2.68359	7.32%	3.68%	11.00%
						Average	10.67%
						Median	10.86%
						Average of Mean and Median	10.77%

Notes:

(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month on a major stock exchange (e.g. NYSE) for each comapny through January 2016.

(2) (1+(Column [1] * Column [2]) ^12) - 1.

(3) From note 2 of Schedule 6.

(4) Column [3] + Column [4].

Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Eighteen Electric Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	4.78 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A Rated Public Utility Bonds	0.33 (2)
3.	Adjusted Prospective Yield on A Rated Public Utility Bonds	5.11 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.40 (3)
5.	Adjusted Prospective Bond Yield	5.51 %
6.	Equity Risk Premium (4)	4.74
7.	Risk Premium Derived Common Equity Cost Rate	10.25 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 9-10 of this Schedule).
(2) The average yield spread of A rated public utility bonds over Aaa rated corporate bonds of 0.33% from page 4 of this Schedule.
(3) Adjustment to reflect the A3 Moody's LT issuer rating of the proxy group as shown on page 6 of this Schedule. The 40 basis point upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 1.20% = 0.40%) as derived from page 4 of this Schedule.

(4) From page 7 of this Schedule.

Interest Rates and Bond Spreads for Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond		[2] A Rated Public Utility Bond		[3] Baa Rated Public Utility Bond	
Nov-15	4.06	%	4.40	%	5.57	%
Dec-15	3.97		4.35		5.55	
Jan-16	4.00		4.27		5.49	
Average	4.01	%	4.34	%	5.54	%

Selected Bond Spreads

A Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.33 % (1)

Baa Rated Public Utility Bonds Over A Rated Public Utility Bonds:
1.20 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional

Comparison of Long-Term Issuer Ratingsfor the
Proxy Group of Eighteen Electric Companies

Proxy Group of Eighteen Electric Companies	Moody's Long-Term Issuer Rating January 2016		Standard & Poor's Long-Term Issuer Rating January 2016	
	Long-Term Issuer Rating	Numerical Weighting(1)	Long-Term Issuer Rating	Numerical Weighting(1)
ALLETE, Inc. (2)	A3	7.000	NR	- -
Alliant Energy Corp. (3)	A2	6.000	A/A-	6.500
Ameren Corp. (4)	A3	7.250	BBB+	8.000
American Electric Power Co., Inc. (5)	Baa1	8.125	BBB	9.000
Consolidated Edison, Inc. (6)	A2/A3	6.500	A-	7.000
Edison International (7)	A2	6.000	BBB+	8.000
El Paso Electric Company	Baa1	8.000	BBB	9.000
Great Plains Energy, Inc. (8)	Baa1/Baa2	8.500	BBB+	8.000
IDACORP, Inc. (9)	A3	7.000	BBB	9.000
OGE Energy Corp. (10)	A1	5.000	A-	7.000
Otter Tail Corp. (11)	A3	7.000	BBB	9.000
PG&E Corp. (12)	A3	7.000	BBB	9.000
Pinnacle West Capital Corp. (13)	A3	7.000	A-	7.000
PNM Resources, Inc. (14)	Baa1	8.000	BBB+	8.000
Portland General Electric Co.	A3	7.000	BBB	9.000
SCANA Corp. (15)	Baa1	8.000	BBB+	8.000
Westar Energy, Inc. (16)	Baa1	8.000	BBB+	8.000
Xcel Energy Inc. (17)	A3	6.750	A-	7.000
Average	A3	7.125	BBB+	8.029

Notes:

(1) From page 6 of this Schedule.
(2) Ratings are those of Superior Water, Light and Power Company
(3) Ratings are those of Interstate Power and Light Co. and Wisconsin Power and Light Co.
(4) Ratings are those of Ameren Illinois Co., Central Illinois Light Co., Illinois Power Co., and Union Electric Co.
(5) Ratings are those of AEP Texas Central Co., AEP Texas North Co., Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Ohio Power Co., Public Service Company of Oklahoma, and Southwestern Electric Power Co.
(6) Ratings are those of Consolidated Edison Co. of New York, Inc. and Orange and Rockland Utilities, Inc.
(7) Ratings are those of Southern California Edison Company.
(8) Ratings are those of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Co.
(9) Ratings are those of Idaho Power Company.
(10) Ratings are those of Oklahoma Gas & Electric Company.
(11) Ratings are those of Otter Tail Power Company.
(12) Ratings are those of Pacific Electric & Gas Company.
(13) Ratings are those of Arizona Public Service Company.
(14) Ratings are those of Public Service Company of New Mexico and Texas-New Mexico Power Company.
(15) Ratings are those of Public Service of North Carolina, Inc. and South Carolina Electric & Gas Company.
(16) Ratings are those of Kansas Gas and Electric Company.
(17) Ratings are those of Northern States Power Company (MN), Northern States Power Company (WI), Public Service Company of Colorado, and Southwestern Public Service Company.

Source Information: www.moodys.com
www.standardandpoors.com

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Judgment of Equity Risk Premium for the Proxy Group of Eighteen Electric Companies

Line No.		Proxy Group of Eighteen Electric Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	5.13 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	3.91
3.	Predicted Equity Risk Premium based on Regression Analysis of 1,098 Fully-Litigated Electric Utility Rate Cases (3)	5.19
4.	Average equity risk premium	4.74 %

Notes: (1) From page 8 of this Schedule.
(2) From page 11 of this Schedule.
(3) From page 12 of this Schedule.

Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
the Proxy Group of Eighteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Eighteen Electric Companies
1.	Ibbotson Equity Risk Premium (1)	5.61 %
2.	Ibbotson Equity Risk Premium based on PRPM™ (2)	7.38
3.	Equity Risk Premium Based on Value Line Summary and Index (3)	8.05
4.	Equity Risk Premium Based on S&P 500 Companies(4)	8.68
5.	Conclusion of Equity Risk Premium (5)	7.43 %
6.	Adjusted Beta (6)	0.69
7.	Forecasted Equity Risk Premium	5.13 %

Notes:
(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Ibbotson® SBBI® 2015 Market Report minus the arithmetic mean monthly yield of Moody's Aaa and Aa corporate bonds from 1928 - 2014. (11.79% - 6.18% = 5.61%).
(2) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns minus the average Aaa and Aa corporate monthly bond yields, from January 1928 through December 2015.

(3) The equity risk premium based on the Value Line Summary and Index is derived from taking the projected 3-5 year total annual market return of 12.83% (described fully in note 1 of Schedule 6) and subtracting the average consensus forecast of Aaa corporate bonds of 4.78% (Shown on page 3 of this Schedule). (12.83% - 4.78% = 8.05%).

(4) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 13.46% was derived based upon expected dividend yields and long-term growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 4.78% results in a expected equity risk premium of 8.68%. (13.46% - 4.78% = 8.68%).
(5) Average of lines 1 through 4.
(6) Average of mean and median beta from Schedule 6.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - Ibbotson® SBBI® 2015 Market Report, Morningstar, Inc., 2015 Chicago, IL.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2015 and February 1, 2016
Bloomberg Professional

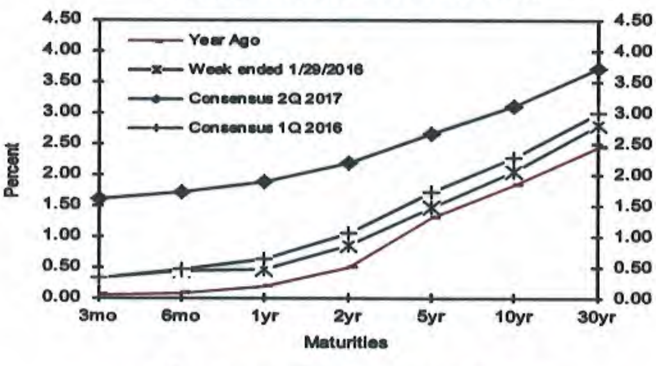
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Jan. 29	Jan. 22	Jan. 15	Jan. 8	Dec.	Nov.	Oct.	4Q2015	2016	2016	2016	2016	2017	2017
Federal Funds Rate	0.38	0.36	0.36	0.27	0.16	0.12	0.12	0.16	0.4	0.6	0.9	1.1	1.3	1.6
Prime Rate	3.50	3.50	3.50	3.50	3.29	3.25	3.25	3.29	3.5	3.7	3.9	4.1	4.4	4.7
LIBOR, 3-mo.	0.62	0.62	0.62	0.61	0.41	0.37	0.32	0.41	0.7	0.9	1.1	1.3	1.6	1.9
Commercial Paper, 1-mo.	0.33	0.34	0.35	0.33	0.17	0.11	0.11	0.17	0.4	0.6	0.9	1.1	1.4	1.7
Treasury bill, 3-mo.	0.31	0.28	0.23	0.21	0.13	0.13	0.02	0.13	0.3	0.5	0.8	1.0	1.3	1.6
Treasury bill, 6-mo.	0.42	0.38	0.44	0.47	0.31	0.33	0.11	0.31	0.5	0.7	0.9	1.1	1.4	1.7
Treasury bill, 1 yr.	0.46	0.46	0.58	0.65	0.25	0.48	0.26	0.46	0.6	0.9	1.1	1.3	1.6	1.9
Treasury note, 2 yr.	0.86	0.86	0.91	0.99	0.83	0.88	0.64	0.83	1.0	1.2	1.5	1.7	1.9	2.2
Treasury note, 5 yr.	1.46	1.47	1.52	1.66	1.59	1.67	1.39	1.59	1.7	1.9	2.1	2.2	2.5	2.7
Treasury note, 10 yr.	2.03	2.04	2.10	2.19	2.19	2.26	2.07	2.19	2.3	2.4	2.6	2.8	2.9	3.1
Treasury note, 30 yr.	2.80	2.80	2.88	2.95	2.96	3.03	2.89	2.96	3.0	3.1	3.3	3.4	3.6	3.7
Corporate Aaa bond	4.04	4.03	3.95	3.98	3.99	4.06	3.95	3.99	4.0	4.2	4.4	4.6	4.7	4.9
Corporate Baa bond	5.48	5.45	5.42	5.46	5.42	5.46	5.34	5.42	5.4	5.5	5.6	5.8	5.9	6.1
State & Local bonds	n.a.	3.37	3.45	3.45	3.64	3.68	3.67	3.64	3.6	3.8	4.0	4.1	4.3	4.4
Home mortgage rate	n.a.	3.81	3.92	3.97	3.90	3.94	3.80	3.90	4.0	4.2	4.4	4.6	4.7	4.9

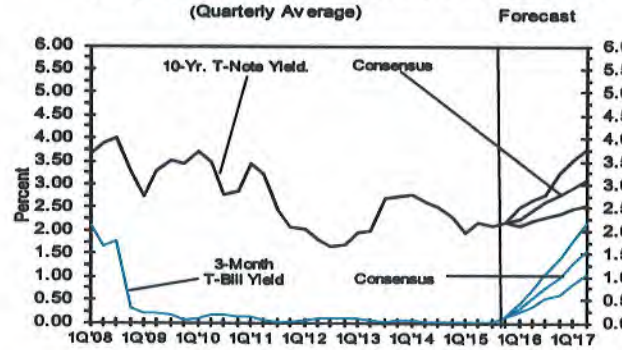
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2014	2014	2014	2014	2015	2015	2015	2015	2016	2016	2016	2016	2017	2017
Major Currency Index	77.1	76.6	77.8	82.6	89.4	89.9	91.8	93.1	94.8	95.6	95.8	95.6	95.3	94.8
Real GDP	-0.9	4.6	4.3	2.1	0.6	3.9	2.0	0.7	2.3	2.5	2.5	2.5	2.4	2.5
GDP Price Index	1.5	2.2	1.6	0.1	0.1	2.1	1.3	0.8	1.2	1.9	1.9	1.9	2.0	2.1
Consumer Price Index	2.1	2.4	1.2	-0.9	-3.1	3.0	1.6	0.2	0.5	2.2	2.2	2.2	2.3	2.5

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Interest rate definitions are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for Fed's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

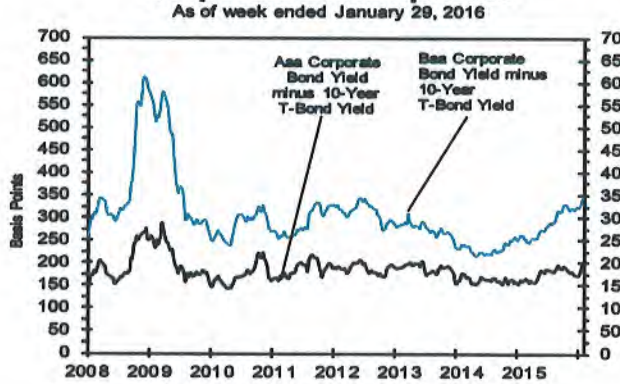
U.S. Treasury Yield Curve
Week ended January 29, 2016 and Year Ago vs.
1Q 2016 and 2Q 2017 Consensus Forecasts



U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)
Forecast



Corporate Bond Spreads
As of week ended January 29, 2016



U.S. Treasury Yield Curve
As of week ended January 29, 2016

Long-Range Estimates:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2017 through 2021 and averages for the five-year periods 2017-2021 and 2022-2026. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
Interest Rates		**2017**	**2018**	**2019**	**2020**	**2021**	**2017-2021**	**2022-2026**
1. Federal Funds Rate	**CONSENSUS**	2.0	2.8	3.2	3.3	3.4	2.9	3.3
	Top 10 Average	2.7	3.6	4.0	4.0	4.0	3.7	3.8
	Bottom 10 Average	1.4	2.1	2.3	2.4	2.7	2.2	2.7
2. Prime Rate	**CONSENSUS**	5.0	5.8	6.2	6.4	6.4	6.0	6.3
	Top 10 Average	5.7	6.5	7.0	7.1	7.0	6.7	6.8
	Bottom 10 Average	4.4	5.2	5.5	5.7	5.8	5.3	5.7
3. LIBOR, 3-Mo.	**CONSENSUS**	2.3	3.1	3.3	3.4	3.6	3.1	3.5
	Top 10 Average	2.8	3.7	4.0	4.2	4.1	3.8	4.0
	Bottom 10 Average	1.8	2.4	2.6	2.7	3.0	2.5	3.0
4. Commercial Paper, 1-Mo.	**CONSENSUS**	2.2	3.0	3.4	3.5	3.4	3.1	3.4
	Top 10 Average	2.6	3.5	3.9	4.1	4.0	3.6	3.8
	Bottom 10 Average	1.7	2.4	2.9	2.9	2.9	2.6	2.9
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	2.0	2.8	3.2	3.3	3.3	2.9	3.2
	Top 10 Average	2.8	3.5	3.9	4.0	3.9	3.6	3.7
	Bottom 10 Average	1.4	2.1	2.5	2.7	2.7	2.3	2.6
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	2.1	2.9	3.3	3.4	3.4	3.0	3.3
	Top 10 Average	3.0	3.6	4.0	4.1	4.0	3.7	3.8
	Bottom 10 Average	1.5	2.2	2.6	2.8	2.8	2.4	2.7
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	2.3	3.1	3.4	3.5	3.5	3.2	3.4
	Top 10 Average	3.2	3.8	4.1	4.2	4.2	3.9	4.0
	Bottom 10 Average	1.6	2.3	2.7	2.9	2.9	2.5	2.8
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	2.5	3.2	3.5	3.6	3.7	3.3	3.7
	Top 10 Average	3.4	4.0	4.4	4.4	4.4	4.1	4.3
	Bottom 10 Average	1.8	2.4	2.6	2.7	3.0	2.5	3.0
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	3.0	3.6	3.8	3.9	4.0	3.6	4.0
	Top 10 Average	3.8	4.4	4.7	4.8	4.8	4.5	4.7
	Bottom 10 Average	2.3	2.7	2.8	2.9	3.2	2.8	3.3
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	3.4	3.8	4.1	4.2	4.3	4.0	4.3
	Top 10 Average	4.2	4.7	5.0	5.2	5.2	4.9	5.1
	Bottom 10 Average	2.8	2.9	3.0	3.2	3.5	3.1	3.5
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	4.0	4.4	4.6	4.8	4.9	4.5	4.8
	Top 10 Average	4.9	5.3	5.7	5.9	5.9	5.5	5.7
	Bottom 10 Average	3.3	3.6	3.5	3.7	3.9	3.6	3.9
13. Corporate Aaa Bond Yield	**CONSENSUS**	5.1	5.5	5.7	5.8	5.8	5.6	5.8
	Top 10 Average	5.7	6.2	6.5	6.6	6.6	6.3	6.5
	Bottom 10 Average	4.5	4.9	5.0	5.0	4.9	4.9	5.2
13. Corporate Baa Bond Yield	**CONSENSUS**	6.0	6.5	6.7	6.8	6.7	6.5	6.8
	Top 10 Average	6.8	7.2	7.6	7.7	7.6	7.4	7.5
	Bottom 10 Average	5.2	5.7	5.9	6.0	5.8	5.7	6.0
14. State & Local Bonds Yield	**CONSENSUS**	4.5	4.9	5.0	5.1	5.1	4.9	5.1
	Top 10 Average	5.0	5.5	5.7	5.8	5.8	5.6	5.8
	Bottom 10 Average	4.0	4.3	4.3	4.4	4.4	4.3	4.4
15. Home Mortgage Rate	**CONSENSUS**	5.1	5.6	5.8	5.9	6.0	5.7	6.0
	Top 10 Average	5.8	6.3	6.7	6.8	6.8	6.5	6.7
	Bottom 10 Average	4.4	4.8	4.9	5.0	5.1	4.9	5.2
A. FRB - Major Currency Index	**CONSENSUS**	92.8	91.7	91.2	90.8	91.1	91.5	90.1
	Top 10 Average	96.9	96.6	96.4	96.4	96.4	96.5	96.0
	Bottom 10 Average	88.4	86.6	85.7	85.1	85.7	86.3	84.2
		Year-Over-Year, % Change					**Five-Year Averages**	
		2017	**2018**	**2019**	**2020**	**2021**	**2017-2021**	**2022-2026**
B. Real GDP	**CONSENSUS**	2.5	2.4	2.2	2.2	2.3	2.3	2.2
	Top 10 Average	2.9	2.8	2.6	2.6	2.6	2.7	2.5
	Bottom 10 Average	2.2	1.8	1.8	1.9	1.9	1.9	2.0
C. GDP Chained Price Index	**CONSENSUS**	2.1	2.1	2.1	2.1	2.1	2.1	2.0
	Top 10 Average	2.3	2.5	2.4	2.3	2.2	2.3	2.2
	Bottom 10 Average	1.8	1.8	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	2.3	2.4	2.3	2.3	2.3	2.3	2.2
	Top 10 Average	2.8	2.8	2.7	2.6	2.5	2.7	2.5
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.1	2.0	2.0

Derivation of Mean Equity Risk Premium Based on a Study
Using Holding Period Returns of Public Utilities

Line No.		Over A Rated Moody's Public Utility Bonds (1)
1.	Arithmetic Mean Holding Period Returns on the Standard & Poor's Utility Index 1928-2015 (2):	10.49 %
2.	Arithmetic Mean Yield on Moody's A Rated Public Utility Yields 1928-2015	(6.64)
3.	Historical Equity Risk Premium	3.85 %
4.	Forecasted Equity Risk Premium Based on PRPM™ (3)	3.90
5.	Forecased Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (4)	3.98
6.	Average of Historical and PRPM™ Equity Risk Premium	3.91 %

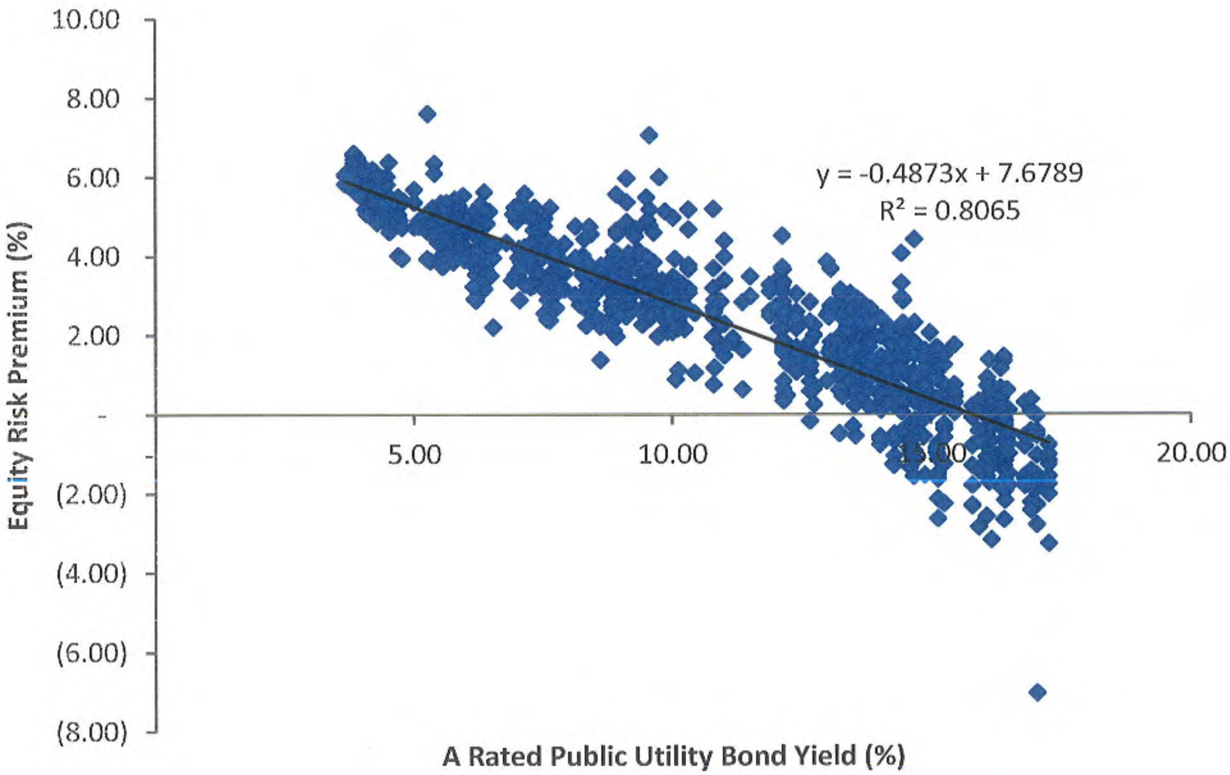
Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2015.

(2) Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A rated public utility bonds from January 1928 - January 2016.

(4) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 9.09% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A rated public utility bond yield of 5.11%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 3.98%. (9.09% - 5.11% = 3.98%)

Prediction of Equity Risk Premiums Relative to
Moody's A rated Utility Bond Yields



Constant	Slope	Prospective A Utility Bond (1)	Prospective Equity Risk Premium
7.6789	-0.4873	5.11 %	5.19 %

Notes:
(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates

Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Eighteen Electric Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
ALLETE, Inc.	0.80	0.5908	0.70	8.49 %	3.68 %	9.62 %	10.26 %	
Alliant Energy Corp.	0.80	0.6234	0.71	8.49	3.68	9.71	10.32	
Ameren Corp.	0.75	0.5901	0.67	8.49	3.68	9.37	10.07	
American Electric Power Co., Inc.	0.70	0.5522	0.63	8.49	3.68	9.03	9.81	
Consolidated Edison, Inc.	0.60	0.4282	0.51	8.49	3.68	8.01	9.05	
Edison International	0.70	0.5160	0.61	8.49	3.68	8.86	9.69	
El Paso Electric Company	0.75	0.6863	0.72	8.49	3.68	9.79	10.39	
Great Plains Energy, Inc.	0.85	0.5971	0.72	8.49	3.68	9.79	10.39	
IDACORP, Inc.	0.80	0.6851	0.74	8.49	3.68	9.96	10.51	
OGE Energy Corp.	0.95	0.6977	0.82	8.49	3.68	10.64	11.02	
Otter Tail Corp.	0.85	0.7240	0.79	8.49	3.68	10.39	10.83	
PG&E Corp.	0.70	0.6162	0.66	8.49	3.68	9.28	10.01	
Pinnacle West Capital Corp.	0.75	0.5974	0.67	8.49	3.68	9.37	10.07	
PNM Resources, Inc.	0.80	0.6205	0.71	8.49	3.68	9.71	10.32	
Portland General Electric Co.	0.80	0.6582	0.73	8.49	3.68	9.88	10.45	
SCANA Corp.	0.75	0.5797	0.66	8.49	3.68	9.28	10.01	
Westar Energy, Inc.	0.75	0.6424	0.70	8.49	3.68	9.62	10.26	
Xcel Energy Inc.	0.65	0.4913	0.57	8.49	3.68	8.52	9.43	
Average			0.68			9.49 %	10.16 %	9.83 %
Median			0.70			9.62 %	10.26 %	9.94 %
Average of Mean and Median			0.69					9.89 %

Please see page 2 for notes.

Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)
Notes Supporting Calculations

Notes:

(1) The market risk premium (MRP) is an average of five different measures. The first measure of the MRP derives the total return on the market by adding the thirteen-week average forecasted 3-5 year capital appreciation to the thirteen-week average expected dividend yield from Value Line Summary and Index. The projected risk-free rate (developed in Note 2) is then subtracted from the total return to arrive at the projected MRP. The second measure of MRP is based on the arithmetic mean of historical monthly return data of large company stocks less the income return on long-term government bonds from 1926-2014 as published by Morningstar, Inc. The third measure applies the PRPM to the Ibbotson historical data to derive a projected MRP. The fourth measure applies a regression analysis to the Ibbotson historical data to derive a projected MRP. The fifth measure uses data from Bloomberg Professional Services to derive a total projected return on the S&P 500 by using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The projected risk-free rate is then subtracted from the projected total return to arrive at the projected MRP. The five measures of MRP are illustrated below:

Measure 1: Value Line Projected MRP (Thirteen weeks ending 2/5/16)	
Total projected return on the market 3 -5 years hence:	12.83 %
Projected Risk-Free Rate (described in Note 2):	3.68
MRP based on Value Line Summary & Index:	9.15 %
Measure 2: Ibbotson Arithmetic Mean MRP (1926 - 2014)	
Arithmetic Mean Monthly Returns for Large Stocks 1926 - 2014:	12.07 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.23
MRP based on Ibbotson Historical Data:	6.84 %
Measure 3: Application of the PRPM to Ibbotson Historical Data: (January1926 - December 2015)	8.32 %
Measure 4: Application of a Regression Analysis to Ibbotson Historical Data: (1926 - 2014)	8.34 %
Measure 5: Bloomberg Projected MRP	
Total return on the Market based on the S&P 500:	13.46 %
Projected Risk-Free Rate (described in Note 2):	3.68
MRP based on Bloomberg data	9.78 %
Average MRP:	8.49 %

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 9 and 10 of Schedule 5) The projection of the risk-free rate is illustrated below:

First Quarter 2016	3.00 %
Second Quarter 2016	3.10
Third Quarter 2016	3.30
Fourth Quarter 2016	3.40
First Quarter 2017	3.60
Second Quarter 2017	3.70
2017 - 2021	4.50
2022 - 2026	4.80
	3.68 %

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Finanical Forecasts dated December 1, 2015 and February 1, 2016
Stocks, Bonds, Bills, and Inflation - Ibbotson® SBBI® 2015 Market Report, Morningstar, Inc., 2015 Chicago, IL.
Bloomberg Professional

FirstEnergy
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Eighteen Electric Companies

The criteria for selection of the proxy group of seventeen non-price regulated companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of seventeen non-price regulated companies were then selected based on the unadjusted beta range of 0.48 – 0.70 and residual standard error of the regression range of 1.7120 – 2.0420 of the electric proxy group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the water industry's residual standard error of the regression is 0.1650. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1650 = \frac{1.8770}{\sqrt{518}} = \frac{1.8770}{22.7596}$$

Source of Information: Value Line, Inc., December 2015
Value Line Investment Survey (Standard Edition)

Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Company Name	Adjusted Beta	Unadjusted Beta	Std. Error	Std. Dev. Beta
ALLETE, Inc.	0.80	0.64	1.8184	0.0526
Alliant Energy Corp.	0.80	0.65	1.6639	0.0482
Ameren Corp.	0.75	0.57	1.8625	0.0539
American Electric Power Co., Inc.	0.70	0.47	1.8216	0.0527
Consolidated Edison, Inc.	0.60	0.35	1.6732	0.0484
Edison International	0.75	0.56	1.8781	0.0544
El Paso Electric Company	0.70	0.52	2.2103	0.0640
Great Plains Energy, Inc.	0.85	0.71	1.8873	0.0546
IDACORP, Inc.	0.80	0.66	1.7970	0.0520
OGE Energy Corp.	0.90	0.78	1.9806	0.0573
Otter Tail Corp.	0.90	0.80	2.2096	0.0640
PG&E Corp.	0.65	0.43	1.9571	0.0567
Pinnacle West Capital Corp.	0.70	0.52	1.7847	0.0517
PNM Resources, Inc.	0.85	0.70	2.5858	0.0749
Portland General Electric Co.	0.80	0.62	1.7828	0.0516
SCANA Corp.	0.75	0.56	1.6193	0.0469
Westar Energy, Inc.	0.75	0.55	1.6301	0.0472
Xcel Energy Inc.	0.65	0.46	1.6238	0.0470
Average	0.76	0.59	1.8770	0.0543

Beta Range (+/- 2 std. Devs. of Beta	0.48	0.70
2 std. Devs. of Beta	0.11	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	1.7120	2.0420
Std. dev. of the Res. Std. Err.	0.0825	
2 std. devs. of the Res. Std. Err.	0.1650	

Source of Information: Valueline Proprietary Database December 2015

Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Eighteen Electric Companies

	[1]	[2]	[3]	[4]
Proxy Group of Seventeen Non-Price-Regulated Companies	VL Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Gallagher (Arthur J.	0.80	0.67	1.8400	0.0533
Becton, Dickinson	0.75	0.61	1.7139	0.0496
Brown-Forman 'B'	0.85	0.70	1.8885	0.0547
Ball Corp.	0.80	0.69	1.7659	0.0511
Costco Wholesale	0.75	0.57	1.7989	0.0521
Amdocs Ltd.	0.85	0.70	1.8670	0.0541
Ecolab Inc.	0.80	0.67	1.8422	0.0533
Erie Indemnity	0.75	0.54	2.0006	0.0579
Hormel Foods	0.70	0.51	1.9110	0.0553
Lilly (Eli)	0.80	0.65	2.0034	0.0580
Progressive (Ohio)	0.85	0.70	1.9863	0.0575
Philip Morris Int'l	0.80	0.68	1.9210	0.0556
Stericycle Inc.	0.80	0.62	1.9854	0.0575
Sysco Corp.	0.75	0.56	1.8159	0.0526
Travelers Cos.	0.80	0.63	1.8119	0.0525
Waste Connections	0.70	0.53	1.9869	0.0575
Berkley (W.R.)	0.70	0.52	1.8068	0.0523
Average	0.78	0.62	1.8792	0.0544
Proxy Group of Eighteen Electric Companies	0.76	0.59	1.8770	0.0543

Summary of Cost of Equity Models Applied to the
Proxy Group of Non-Price-Regulated Companies
Comparable in Total Risk to the
Proxy Group of Eighteen Electric Companies

Principal Methods	Proxy Group of Seventeen Non-Price-Regulated Companies	
Discounted Cash Flow Model (DCF) (1)	11.16	%
Risk Premium Model (RPM) (2)	11.29	
Capital Asset Pricing Model (CAPM) (3)	10.86	
Mean	11.10	%
Median	11.16	%
Average of Mean and Median	11.13	%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk tc
the Proxy Group of Eighteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seventeen Non-Price-Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Reuters Mean Consensus Projected Five Year Growth Rate in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate
Gallagher (Arthur J.	3.68 %	14.50 %	8.05 %	7.90 %	8.10 %	9.64 %	3.86 %	13.50 %
Becton, Dickinson	1.76	11.50	13.59	11.10	13.59	12.45	1.87	14.32
Brown-Forman 'B'	1.36	8.00	8.00	8.70	NA	8.23	1.42	9.65
Ball Corp.	0.75	9.50	6.00	10.50	6.00	8.00	0.78	8.78
Costco Wholesale	1.01	10.50	8.52	10.40	8.53	9.49	1.06	10.55
Amdocs Ltd.	1.41	8.00	6.80	7.40	6.80	7.25	1.46	8.71
Ecolab Inc.	1.24	11.00	12.06	13.20	12.06	12.08	1.31	13.39
Erie Indemnity	3.12	11.00	10.00	10.00	10.00	10.25	3.28	13.53
Hormel Foods	1.54	12.00	15.07	11.10	15.08	13.31	1.64	14.95
Lilly (Eli)	2.46	8.00	13.72	11.90	13.72	11.84	2.61	14.45
Progressive (Ohio)	2.86	11.50	6.80	9.50	6.66	8.62	2.98	11.60
Philip Morris Int'l	4.67	7.50	(1.82)	7.20	2.79	5.83	4.81	10.64
Stericycle Inc.	-	10.00	NA	14.30	15.00	13.10	-	NA
Sysco Corp.	3.05	12.00	7.68	7.30	8.33	8.83	3.18	12.01
Travelers Cos.	2.20	4.50	1.67	7.70	2.94	4.20	2.25	6.45
Waste Connections	1.05	9.50	7.89	8.70	7.89	8.50	1.09	9.59
Berkley (W.R.)	0.90	9.00	(3.61)	9.00	0.59	6.20	0.93	7.13
							Mean	11.20 %
							Median	11.12 %
						Average of Mean and Median		11.16 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regluated comparable risk companies is identical to the application of the DCF to the proxy group of utility companies. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of January 29, 2016. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.reuters.com, www.zacks.com, and www.yahoo.com (excluding any negative growth rates). That adjusted dividend yield is then added to the growth rate which results in the indicated cost of common equity.

Source of Information: Value Line Investment Survey:
www.reuters.com Downloaded on 01/29/2016
www.zacks.com Downloaded on 01/29/2016
www.yahoo.com Downloaded on 01/29/2016

Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seventeen Non-Price-Regulated Companies
1.	Prospective Yield on Baa Rated Corporate Bonds (1)	5.83 %
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.71)
3.	Adjusted Prospective Bond Yield	5.12
4.	Equity Risk Premium (3)	6.17
5.	Risk Premium Derived Common Equity Cost Rate	11.29 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated December 1, 2015 and February 1, 2016 (see pages 9-10 of Schedule 5). The estimates are detailed below.

First Quarter 2016	5.20 %
Second Quarter 2016	5.30
Third Quarter 2016	5.40
Fourth Quarter 2016	5.60
First Quarter 2017	5.70
Second Quarter 2017	5.80
2017 - 2021	6.70
2022 - 2026	6.90
Average	5.83 %

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending January 2015. To reflect the A3 average rating of the non-utility proxy group, the prosepctive yield on Baa corporate bonds must be adjusted downward by 2/3 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield	Baa Corp. Bond Yield	Spread
Nov-15	4.43 %	5.46 %	1.03 %
Dec-15	4.38	5.46	1.08
Jan-16	4.35	5.45	1.10
		Average yield spread	1.07 %
		2/3 of spread	0.71 %

(3) From page 5 of this Schedule.

Comparison of Long-Term Issuer Ratings for the
Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Eighteen Electric Companies

	Moody's Long-Term Issuer Rating January 2016		Standard & Poor's Long-Term Issuer Rating January 2016	
Proxy Group of Seventeen Non-Price-Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Gallagher (Arthur J.	NR	--	NR	--
Becton, Dickinson	Baa2	9.0	BBB+	8.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Ball Corp.	Ba1	11.0	BB+	11.0
Costco Wholesale	A1	5.0	A+	5.0
Amdocs Ltd.	Baa2	9.0	BBB	9.0
Ecolab Inc.	Baa1	8.0	BBB+	8.0
Erie Indemnity	NR	--	NR	--
Hormel Foods	A1	5.0	A	6.0
Lilly (Eli)	A2	6.0	AA-	4.0
Progressive (Ohio)	A2	6.0	A+	5.0
Philip Morris Int'l	A2	6.0	A	6.0
Stericycle Inc.	NR	--	A	6.0
Sysco Corp.	A2	6.0	A-	7.0
Travelers Cos.	A2	6.0	A	6.0
Waste Connections	NR	--	BBB+	8.0
Berkley (W.R.)	Baa2	9.0	BBB+	8.0
Average	A3	7.0	A-	6.9

Notes:
(1) From page 6 of Schedule 5.

Source of Information:
Bloomberg Professional

Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
the Proxy Group of Non-Price-Regulated Companies
Proxy Group of Eighteen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seventeen Non-Price-Regulated Companies
1.	Ibbotson Equity Risk Premium (1)	5.61 %
2.	Ibbotson Equity Risk Premium based on PRPM (2)	7.38
3.	Equity Risk Premium Based on Value Line Summary and Index (3)	8.05
4.	Equity Risk Premium Based on S&P 500 Companies (4)	8.68
5.	Conclusion of Equity Risk Premium (5)	7.43 %
6.	Adjusted Beta (6)	0.83
7.	Forecasted Equity Risk Premium	6.17 %

Notes:
(1) From page 8, note 1 of Schedule 5.
(2) From page 8, note 2 of Schedule 5.
(3) From page 8, note 3 of Schedule 5.
(4) From page 8, note 4 of Schedule 5.
(5) Average of lines 1 through 4.
(6) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:

Ibbotson® SBBI® 2015 Classic Yearbook - Market Results for Stocks, Bonds, Bills, and Inflation, Morningstar, Inc., 2015 Chicago, IL.

Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2015 and February 1, 2016
Bloomberg Professional

Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Eighteen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seventeen Non-Price-Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Gallagher (Arthur J.	0.85	0.88	0.86	8.49 %	3.68 %	10.98 %	11.28 %	
Becton, Dickinson	0.75	0.79	0.77	8.49	3.68	10.22	10.71	
Brown-Forman 'B'	0.90	0.96	0.93	8.49	3.68	11.58	11.72	
Ball Corp.	0.90	0.95	0.92	8.49	3.68	11.49	11.66	
Costco Wholesale	0.75	0.83	0.79	8.49	3.68	10.39	10.83	
Amdocs Ltd.	0.90	0.95	0.93	8.49	3.68	11.58	11.72	
Ecolab Inc.	0.90	1.06	0.98	8.49	3.68	12.00	12.04	
Erie Indemnity	0.75	0.75	0.75	8.49	3.68	10.05	10.58	
Hormel Foods	0.75	0.77	0.76	8.49	3.68	10.13	10.64	
Lilly (Eli)	0.80	0.72	0.76	8.49	3.68	10.13	10.64	
Progressive (Ohio)	0.85	0.91	0.88	8.49	3.68	11.15	11.41	
Philip Morris Int'l	0.80	0.76	0.78	8.49	3.68	10.30	10.77	
Stericycle Inc.	0.80	0.60	0.70	8.49	3.68	9.62	10.26	
Sysco Corp.	0.70	0.75	0.73	8.49	3.68	9.88	10.45	
Travelers Cos.	0.85	0.86	0.86	8.49	3.68	10.98	11.28	
Waste Connections	0.75	0.96	0.85	8.49	3.68	10.90	11.21	
Berkley (W.R.)	0.80	0.83	0.82	8.49	3.68	10.64	11.02	
		Mean	0.83			10.71 %	11.07 %	10.89 %
		Median	0.82			10.64 %	11.02 %	10.83 %
	Average of Mean and Median		0.83					10.86 %

Notes:
(1) From Schedule 6, note 1.
(2) From Schedule 6, note 2.
(3) Average of CAPM and ECAPM cost rates.

Derivation of the Floatation Cost Adjustment to the Cost of Common Equity

Equity Issuances and Floatation Costs of the Parent Since 2003

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]	[Column 8]	[Column 9]	[Column 10]
Date	Transaction (1)	Shares Issued	Market Price per Share	Offering Price per Share	Market Pressure (2)	Underwriting Discount	Net Proceeds per Share (3)	Gross Equity Issue before Costs (4)	Total Net Proceeds (5)	Total Floatation Costs (6)	Flotation Cost Perecentage (7)
09/11/03	Equity Issuance	32,200,000	$ 31.1000	$ 30.0000	$ 1.1000	$ 0.9750	$ 29.0250	$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%
								$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (8)	DCF Cost Rate Adjusted for Flotation (9)	Flotation Cost Adjustment
Proxy Group of Eighteen Electric Companies	3.69 %	5.09 %	3.78 %	8.87 %	9.14 %	0.27 % (10)

Notes are on page 2 of this Schedule

FirstEnergy
Notes to Accompany the
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

(1) Company-provided.

(2) Column 2 – Column 3.

(3) Column 2 – the sum of columns 4 and 5.

(4) Column 1 * Column 2.

(5) Column1 * Column 6.

(6) Column1 * (the sum of columns 4 and 5).

(7) (Column 7 – Column 8) divided by Column 7.

(8) Using the average growth rate from Schedule 4.

(9) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g,$$

where g is the growth factor and F is the percentage of flotation costs.

(10) Flotation cost adjustment of 0.27% equals the difference between the flotation adjusted average DCF cost rate of 9.14% and the unadjusted average DCF cost rate of 8.87% of the proxy group.

Source of Information:

Company provided information

Metropolitan Edison Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on January 29, 2016 (1) (millions)	[1] (times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Metropolitan Edison Company	$ 1,337.390		7	1.71%	
2.	Proxy Group of Eighteen Electric Companies	$ 9,647.332	7.2 x	3	0.91%	0.80%

	(A) Decile	(B) Number of Companies (millions)	(C) Recent Total Market Capitalization (millions)	(D) Recent Average Market Capitalization (millions)	(E) Size Premium (Return in Excess of CAPM) (2)
Largest	1	191	$ 14,808,784.274	$ 77,532.902	-0.36%
	2	208	3,247,447.914	15,612.730	0.63%
	3	198	1,579,432.904	7,976.934	0.91%
	4	222	1,042,428.212	4,695.623	1.06%
	5	222	694,147.086	3,126.789	1.60%
	6	272	585,657.120	2,153.151	1.74%
	7	323	449,325.225	1,391.100	1.71%
	8	421	333,731.801	792.712	2.15%
	9	413	173,673.205	420.516	2.69%
Smallest	10	951	135,401.288	142.378	5.78%

*From Duff & Phelps 2015 Valuation Handbook Guide to Cost of Capital

Notes:

(1) From page 2 of this Schedule.
(2) Gleaned from Column (D) on the bottom of this page. The appropriate decile (Column (A)) corresponds to the market capitalization of the proxy group, which is found in Column 1.
(3) Corresponding risk premium to the decile is provided on Column (E) on the bottom of this page.
(4) Line No. 1a Column 3 – Line No. 2 Column 3 and Line No. 1b, Column 3 – Line No. 3 of Column 3 etc.. For example, the 0.80% in Column 4, Line No. 2 is derived as follows 0.80% = 2.69% - 0.91%.

Metropolitan Edison Company
Market Capitalization of Metropolitan Edison Company and
the Proxy Group of Eighteen Electric Companies

Company	Exchange	[1] Common Stock Shares Outstanding at 2014 Fiscal Year End	[2] Book Value Per Share at Fiscal Year End (1)	[3] Total Common Equity at Fiscal Year End 2014 (millions)	[4] Closing Stock Market Price on January 29, 2016	[5] Market-to-Book Ratio on January 29, 2016 (2)	[6] Market Capitalization on January 29, 2016 (3) (millions)
Metropolitan Edison Company		NA	NA	$ 792.762 (4)	NA		
Based upon the Proxy Group of Eighteen Electric Companies						168.7 (5)	$ 1,337.390 (6)
Proxy Group of Eighteen Electric Companies							
ALLETE, Inc.	NYSE	45.900	$ 35.06	$ 1,609.400	$ 52.92	150.9 %	$ 2,429.03
Alliant Energy Corp.	NYSE	110.936	$ 31.00	$ 3,438.700	$ 65.31	210.7	10,254.702
Ameren Corp.	NYSE	242.600	$ 27.67	$ 6,713.000	$ 44.92	162.3	27,907.153
American Electric Power Co., Inc.	NYSE	489.403	$ 34.37	$ 16,820.000	$ 60.97	177.4	2,474.010
Consolidated Edison, Inc.	NYSE	292.876	$ 42.94	$ 12,576.000	$ 69.35	161.5	19,592.673
Edison International	NYSE	325.811	$ 33.64	$ 10,960.000	$ 61.78	183.7	20,548.913
El Paso Electric Company	NYSE	40.108	$ 24.54	$ 984.254	$ 40.90	166.7	4,170.920
Great Plains Energy, Inc.	NYSE	154.163	$ 23.26	$ 3,586.100	$ 27.89	119.9	3,257.546
IDACORP, Inc.	NYSE	50.270	$ 38.85	$ 1,953.201	$ 69.61	179.2	6,630.451
OGE Energy Corp.	NYSE	199.400	$ 16.27	$ 3,244.400	$ 26.22	161.2	5,463.862
Otter Tail Corp.	NYSE	37.218	$ 15.39	$ 572.766	$ 27.84	180.9	983.143
PG&E Corp.	NYSE	475.913	$ 33.09	$ 15,748.000	$ 54.90	165.9	25,881.390
Pinnacle West Capital Corp.	NYSE	110.571	$ 39.50	$ 4,367.493	$ 66.31	167.9	2,234.284
PNM Resources, Inc.	NYSE	79.654	$ 21.61	$ 1,721.546	$ 31.41	145.3	7,109.731
Portland General Electric Co.	NYSE	78.228	$ 24.43	$ 1,911.000	$ 38.87	159.1	3,281.907
SCANA Corp.	NYSE	142.700	$ 34.95	$ 4,987.000	$ 62.94	180.1	8,039.554
Westar Energy, Inc.	NYSE	131.687	$ 25.02	$ 3,294.856	$ 43.55	174.1	5,430.376
Xcel Energy Inc.	NYSE	505.733	$ 20.20	$ 10,214.482	$ 38.20	189.1	17,962.334
Average						168.7 %	$ 9,647.332

NA= Not Available

Notes: (1) Column [3] divded by Column [1].
(2) Column [4] divided by Column [2].
(3) Column [1] multiplied by Column [4].
(4) The Company's common equity balance in their 2014 annual report.
(5) The market-to-book ratio of 168.7% on January 29, 2016 is assumed to be equal to the market-to-book ratio of the proxy group at January 29, 2016.
(6) The Company's common stock, if traded, would trade at a market-to-book ratio equal to the average market-to-book ratio of the proxy group at January 29, 2016, 168.7%, and the Company's market capitalization on January 29, 2016 would therefore have been $1,337.390 million.

Source of Information: 2014 Annual Forms 10K
yahoo.finance.com

Statement No. 9

Met-Ed Statement No. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2016-2537349

Direct Testimony
of
Joseph Dipre

List of Topics Addressed

Capital Structure
Cost of Long-Term Debt
Weighted Average Cost of Capital

TABLE OF CONTENTS

DIRECT TESTIMONY
OF
JOSEPH DIPRE

I. <u>INTRODUCTION AND PURPOSE</u>

Q. Please state your name and business address.

A. My name is Joseph Dipre and my business address is 76 South Main Street, Akron, Ohio 44308.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company. My title is Sr. Advisor, Strategy & Long-Term Planning.

Q. What are your current responsibilities?

A. I am responsible for supporting finance-related activities, including budgeting, forecasting, and financial planning. My responsibilities primarily focus on the regulated companies owned by FirstEnergy Corp. ("FirstEnergy") and its subsidiaries, including its Pennsylvania distribution operating companies.

Q. Please describe your educational and professional experience.

A. I am a graduate of Defiance College with undergraduate degrees in Business/Accounting and Mathematics. I earned my CPA status from the State of Ohio in February 1994. I began my professional career at Ducato and Kline, CPA, performing in various accounting-related roles between 1986 and 1989. My utility industry career began with Centerior Energy Corporation (a predecessor to FirstEnergy) in 1989 as a Tax Analyst in the Tax Department. In 2004, I moved over to FirstEnergy's Strategic Planning Department as a Financial Analyst and served in a similar role in the Business Planning Department. I was promoted to Sr. Financial Analyst, Staff Business Analyst, and Consultant over time. In 2005, I was promoted as Manager of Financial Studies and Capital Planning. In 2007, I was assigned to the Business Development Department as Manager of Business Development and Performance Management and in 2009 was promoted as Sr. Business Development Advisor. I maintained the Sr. Advisor title when I moved to the Treasury Department in 2011 and to my current department, Strategy & Long-Term Planning, in 2015.

Q. On whose behalf are you testifying in this matter?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed").

Q. What is the purpose of your direct testimony?

A. My testimony describes and supports the capital structure, embedded cost of long-term debt and overall weighted average cost of capital claimed by Met-Ed.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring responses to various standard filing requirements dealing with financial matters, which responses are sequentially numbered as Exhibits JD-1 through JD-21 for Met-Ed. In addition, I am sponsoring the following summary schedules for Met-Ed, which will be discussed further in this testimony:

Exhibit JD-22: Capitalization & Capitalization Ratios

Exhibit JD-23: Schedule of Long-Term Debt Outstanding at 12/31/2017

Exhibit JD-24: Capital Cost Rates 12/31/2017

Each of these exhibits was prepared by me or under my supervision.

II. CAPITAL STRUCTURE

Q. What capital structure ratios are you proposing be utilized for purposes of determining Met-Ed's overall weighted average cost of capital?

A. I recommend use of Met-Ed's projected capital structure at December 31, 2017, exclusive of short-term debt. That date corresponds to the end of the fully projected future test year in these proceedings and, accordingly, reflects the mix of long-term debt and common equity capital that will support Met-Ed's claimed rate base.

Q. Why have you excluded short-term debt from your proposed capital structure ratios?

A. Short-term borrowings typically are sources of liquidity and are not utilized to finance long-lived assets, such as those included in Met-Ed's claimed rate base. In addition, it is my understanding that the Pennsylvania Public Utility Commission typically excludes short-term debt from a utility's capital structure in base rate cases.

Q. How did you derive Met-Ed's anticipated capital structure ratios at December 31, 2017?

A. As set forth in Exhibit JD-22, the starting point was the actual capital structure in place at December 31, 2015, which represents the end of the historic test year. Then, based on recent financial forecasts, the respective amounts of long-term debt and common equity[1] were adjusted forward to December 31, 2016, the end of the future test year, and to December 31, 2017, the end of the fully projected future test year, to capture: (1) consummated and planned issuances of long-term debt; (2) the pay down of long-term debt; (3) the amortization of long-term debt discount; (4) planned equity infusions; and (5) anticipated increases in retained earnings.

Q. What specific capital structure ratios do you recommend be adopted for rate of return purposes in this case?

A. Since rate setting is prospective, the rate of return should reflect a utility's expected capital structure at the end of the fully projected future test year. I therefore recommend the adoption of the projected December 31, 2017 capital structure ratios of 48.8% long-term debt and 51.2% common equity.

III. COST OF LONG-TERM DEBT

Q. What cost rate have you assigned to the long-term debt component of Met-Ed's capital structure?

A. The determination of a utility's weighted average long-term debt cost rate is essentially an arithmetic exercise due to the fact that the utility has contracted for the use of the capital in question for a defined period of time at a specified cost rate. The necessary calculations, which take into account issuance expense, are provided in Exhibit JD-23.

Q. Please describe what is shown in Exhibit JD-23.

[1] Met-Ed has no preferred or preference stock outstanding.

A. Exhibit JD-23 itemizes each series of debt, the date of issuance, maturity, original amount issued and projected amount outstanding as of December 31, 2017. The Premium/Discount and Issuance Expenses column represents legal, underwriting and other miscellaneous costs associated with each issuance. The principal amount issued, adjusted for any premium or discount, less any issuance expenses equals the Net Proceeds. The effective rate is calculated by taking the Net Proceeds at the time of issuance and calculating the Internal Rate of Return based on the interest rate and the years to maturity. After the effective rate is calculated for each individual series, the rates are weighted by taking the effective rate multiplied by each respective amount outstanding divided by the total adjusted amount of long-term debt outstanding.

Q. What long-term debt cost rate do you recommend be utilized in developing Met-Ed's overall cost of capital?

A. As indicated in Exhibit JD-23, Met-Ed's projected weighted average long-term debt cost rate is 5.25%.

IV. OVERALL COST OF CAPITAL

Q. How did you calculate Met-Ed's overall cost of capital?

A. As set forth in Exhibit JD-24, I quantified, and then combined, Met-Ed's weighted average cost of long-term debt and cost of common equity by multiplying the projected December 31, 2017 capitalization ratios presented in Exhibit JD-22 by: (1) the average cost of debt developed on Exhibit JD-23; and (2) Met-Ed's requested return on common equity of 10.90%. The proposed cost of equity is supported by Ms. Pauline Ahern in Met-Ed Statement No. 8. Met-Ed's overall weighted cost of capital is 8.14%.

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

DB1/ 87345853.2

Exhibits

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-5:

"If a claim is made for compensating bank balances, provide the following information:

(a) Name and address of each bank.
(b) Types of accounts with each bank – checking, savings, escrow, other services, and the like.
(c) Average daily balance in each account.
(d) Amount and percentage requirements for compensating bank balance at each bank.
(e) Average daily compensating bank balance at each bank.
(f) Documents from each bank explaining compensating bank balance requirements.
(g) Interest earned on each type of account.
(h) A calculation showing the average daily float for each bank."

RESPONSE:

No compensating bank balances are maintained.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-E-2:

"Supply summaries of the utility's projected operating and capital budgets for the 2 calendar years following the end of the test year."

RESPONSE:

See Met-Ed Exhibit JD-2 Attachment A.

Met-Ed
FORECASTED STATEMENTS OF INCOME
($Millions)

	2018	2019
Total Revenues	769	829
Total Operating & Maintenance Exp.	494	551
Depreciation & Amortization	75	78
Taxes Other Than Income Taxes	51	55
Total Operating Expense	620	684
Operating Income Before Income Taxes	149	145
Income Taxes-Operating	38	37
Operating Income After Income Taxes	111	108
Total Other Income & Deductions	22	25
Interest Expense	58	55
AFUDC	(1)	0
Total Interest Expense	57	55
Net Income Before Preferred Dividends	76	78
Preferred Dividends	0	0
Earnings Available for Common Stock	76	78

ME Exhibit JD-2
Attachment A
Witness: J. Dipre

Met-Ed - Forecasted Capital Expenditures ($ Millions)

	2018 Forecast	2019 Forecast
Generation	$ -	$ -
Transmission	-	-
Distribution	111	111
Other	1	1
Total	$ 112	$ 112
Less AFUDC	1	-
Construction (Excl. AFUDC)	$ 111	$ 112

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-A-1:

> "Provide a schedule showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data."

RESPONSE:

See Met-Ed Statement No. 9, the direct testimony of Joseph Dipre, and accompanying exhibits.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-A-2:

"Provide a schedule in the same format as Schedule 1, except for the omission of the descriptive statement, for the most immediate comparable annual historical period prior to the test year and the two calendar years most immediately preceding the rate of return claim period. Irrespective of whether the capitalization claimed on Schedule 1 includes short-term debt, Schedule 2 should reflect capital ratios with and without short-term debt."

RESPONSE:

See Met-Ed Exhibit JD-4 Attachment A.

Metropolitan Edison Company
Capitalization & Capitalization Ratios
($000)

	Actuals		Forecast	
	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Capitalization				
Long Term Debt	848,998	849,104	849,210	849,316
Preferred Stock				
Common Equity	792,762	797,349	867,833	889,984
Total	1,641,760	1,646,453	1,717,043	1,739,300
Short-term Debt	33,470	53,836	30,942	34,185
Total	1,675,230	1,700,289	1,747,985	1,773,485
Capitalization Ratios				
Long Term Debt	51.7%	51.6%	49.5%	48.8%
Preferred Stock	0.0%	0.0%	0.0%	0.0%
Common Equity	48.3%	48.4%	50.5%	51.2%
Total (without st-debt)	100.0%	100.0%	100.0%	100.0%
Long term Debt	50.7%	49.9%	48.6%	47.9%
Preferred Stock	0.0%	0.0%	0.0%	0.0%
Common Equity	47.3%	46.9%	49.6%	50.2%
Short-term Debt	2.0%	3.2%	1.8%	1.9%
Total	100.0%	100.0%	100.0%	100.0%

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-1:

"Provide a schedule showing the calculation of embedded cost of long-term debt by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.
b. Date of maturity.
c. Amount issued.
d. Amount outstanding.
e. Amount retired.
f. Amount reacquired.
g. Gain or loss on reacquisition.
h. Coupon rate.
i. Discount or premium at issuance.
j. Issuance expense.
k. Net proceeds.
l. Sinking fund requirements.
m. Effective cost rate.
n. Total average weighted effective cost rate.

Projected new issues, retirements and other major changes from the comparable historic data should be clearly noted."

RESPONSE:

See Met-Ed Exhibit JD-5 Attachment A.

Met-Ed
Schedule of Long Term Debt Outstanding at 12/31/2017

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(3,006,738)	296,993,262		3.6204%	
4.00% Series	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,758,140)	247,241,860		4.1258%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(2,372,217)	297,627,783		7.8154%	
			850,000,000	**850,000,000**	-				**(8,137,095)**	**841,862,905**			**5.2496%**

Met-Ed
Schedule of Long Term Debt Outstanding at 12/31/2016

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(3,006,738)	296,993,262		3.6204%	
4.00% Series	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,758,140)	247,241,860		4.1258%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(2,372,217)	297,627,783		7.8154%	
			850,000,000	**850,000,000**	-				**(8,137,095)**	**841,862,905**			**5.2496%**

Met-Ed
Schedule of Long Term Debt Outstanding at 12/31/2015

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(3,006,738)	296,993,262		3.6204%	
4.00% Series	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,758,140)	247,241,860		4.1258%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(2,372,217)	297,627,783		7.8154%	
			850,000,000	**850,000,000**	-				**(8,137,095)**	**841,862,905**			**5.2496%**

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-2:

"In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-3:

"Provide the following information concerning bank notes payable for test year and for latest comparable annual historical period prior to the test year:

a. Line of credit at each bank.
b. Average daily balances of notes to each bank, by name of bank.
c. Interest rate charged on each bank note (Prime rate, formula rate, or other).
d. Purpose of each bank note (for example, construction, fuel storage, working capital, debt retirement).
e. Prospective future need for this type of financing."

RESPONSE:

a. Met-Ed can borrow up to $500 mm under the FirstEnergy Corp. Revolving Credit Facility ("Revolver"). Mizuho is the administrative agent for this credit facility.

b. As of 12/31/2015, Met-Ed had no borrowings outstanding under the Revolver.

c. Met-Ed did not have any borrowings outstanding under the Revolver as of 12/31/2015, however the interest rate if it had borrowings would have been one month LIBOR plus 150 basis points.

d. Working capital requirements.

e. Working capital requirements.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-4:

"Provide detailed information concerning all other short-term debt outstanding."

RESPONSE:

Met-Ed is a participant in the Utility Money Pool and borrows and invests in the pool as needed. The balance borrowed from the Utility Money Pool at 12/31/2015 was $53.8 mm and the borrowing rate was 0.64%.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-C:

"Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.
b. Date of maturity.
c. Amount issued.
d. Amount outstanding.
e. Amount retired.
f. Amount reacquired.
g. Gain or loss on reacquisition.
h. Dividend rate.
i. Discount or premium issuance.
j. Issuance expenses.
k. Net proceeds.
l. Sinking fund requirements.
m. Effective cost rate.
n. Total average weighted effective cost rate.

Projected new issues, retirement and other major changes from the comparable historical data should be clearly noted."

RESPONSE:

Not applicable

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-2:

"Provide a summary statement of all stock dividends, splits or par value changes during the 2 calendar year period preceding the rate case filing."

RESPONSE:

See Met-Ed Exhibit JD-10 Attachment A.

Metropolitan Edison Company

Common Stock Dividend Record

Payment Date	Common Dividend	Return of Capital	Stock Re-purchase
Nov-14		50,000,000	
Nov-15	45,000,000	15,000,000	

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-3:

"Provide a schedule of all issuances of common stock, whether or not underwriters are used, for the most immediately available annual historical period and the 2 calendar years most immediately preceding the test year."

RESPONSE:
Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-4:

"Submit details on the utility and parent company stock offerings—past 5 years to present - as follows:

a. Date of prospectus.
b. Date of offering.
c. Record date.
d. Offering period – dates and numbers of days.
e. Amount and number of shares offered.
f. Offering ratio, if rights offering.
g. Percent subscribed.
h. Offering price.
i. Gross proceeds per share.
j. Expenses per share.
k. Net proceeds per share (i—j).
l. Market price per share.
   (1) At record date.
   (2) At offering date.
   (3) One month after close of offering.
m. Average market price during offering.
   (1) Price per share.
   (2) Rights per share—average value of rights.
n. Latest reported earning per share at time of offering.
o. Latest reported dividends at time of offering."

RESPONSE:

The only public issuance of common stock by FirstEnergy Corp. ("First Energy") in the past five years involved the exchange of 113,381,030 shares in connection with the Allegheny Energy merger. The dollar amount of the equity issued was $4,326,620,111.82 and was based on the closing price of FirstEnergy stock on February 24, 2011, the day before the effective date of the merger, of $38.16 per share.

In the 4th Quarter of 2013, FirstEnergy started issuing shares under the Stock Investment Plan (SIP), Divided Re-Investment Plan (DRIP), and certain Human Resources benefit programs that will provide approximately $100 mm per year of additional equity.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-1:

"If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system – consolidated - the reasons for this claim must be fully stated and supported."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-2:

"Regardless of the claim made, provide the capitalization data requested at Item III.A.2. for the parent company and for the system - consolidated."

RESPONSE:

See Met-Ed Exhibit JD-14 Attachment A.

FirstEnergy Corp (Stand Alone/Parent)
Capitalization & Capitalization Ratios
($ Millions)

	Actuals	
	12/31/2014	12/31/2015
Capitalization		
Long Term Debt	4,223	4,212
Preferred Stock		
Common Equity	12,206	12,248
Total	16,429	16,460
Short-term Debt	1,901	1,881
Total	18,330	18,341
Capitalization Ratios		
Long Term Debt	25.7%	25.6%
Preferred Stock	0.0%	0.0%
Common Equity	74.3%	74.4%
Total	100.0%	100.0%
Long term Debt	23.0%	23.0%
Preferred Stock	0.0%	0.0%
Common Equity	66.6%	66.8%
Short-term Debt	10.4%	10.3%
Total	100.0%	100.0%

FirstEnergy Corp (Consolidated)
Capitalization & Capitalization Ratios
($ Millions)

	Actuals 12/31/2014	Actuals 12/31/2015
Capitalization		
Long Term Debt	19,980	20,358
Preferred Stock		
Common Equity	12,422	12,422
Total	32,402	32,780
Short-term Debt	1,799	1,708
Total	34,201	34,488
Capitalization Ratios		
Long Term Debt	61.7%	62.1%
Preferred Stock	0.0%	0.0%
Common Equity	38.3%	37.9%
Total	100.0%	100.0%
Long term Debt	58.4%	59.0%
Preferred Stock	0.0%	0.0%
Common Equity	36.3%	36.0%
Short-term Debt	5.3%	5.0%
Total	100.0%	100.0%

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-3:

"Provide the latest available balance sheet and income statement for the parent company and system – consolidated."

RESPONSE:

See Met-Ed Exhibit JD-15 Attachment A.

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

FORM 10-K

(Mark One)

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

For the FISCAL YEAR ended December 31, 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 Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
000-53742	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, $0.10 par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Registrant	Title of Each Class
FirstEnergy Solutions Corp.	Common Stock, no par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☑ No ☐ FirstEnergy Corp.
Yes ☐ No ☑ FirstEnergy Solutions Corp.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☑ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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

☐ FirstEnergy Corp.
☐ FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant 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 ☑	FirstEnergy Corp.
Accelerated Filer ☐	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) ☑	FirstEnergy Solutions Corp.
Smaller Reporting Company ☐	N/A

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

Yes ☐ No ☑ FirstEnergy Corp. and FirstEnergy Solutions Corp.

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter.

FirstEnergy Corp., $13,727,177,963 as of June 30, 2015; and for FirstEnergy Solutions Corp., none.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF JANUARY 31, 2016
FirstEnergy Corp., $0.10 par value	423,650,645
FirstEnergy Solutions Corp., no par value	7

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.

Documents Incorporated By Reference

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2016 Annual Meeting of Shareholders to be held May 17, 2016	Parts II and III

This combined Form 10-K is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. Information contained herein relating to an individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to the other registrant, except that information relating to FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Forward-Looking Statements: Certain of the matters discussed in this Annual Report on Form 10-K are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors with respect to such Registrants discussed in (a) Item 1A. Risk Factors, (b) Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-K. Neither of the Registrants undertake any obligation to update these statements, except as required by law.

TABLE OF CONTENTS

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, which provided legal, financial and other corporate support services to the former AE subsidiaries
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities
Buchanan Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply
Buchanan Generation	Buchanan Generation, LLC, a joint venture between AE Supply and CNX Gas Corporation
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FELHC, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI and TrAIL and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly-owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly-owned subsidiary of FG, which owns various leasehold interests in Bruce Mansfield Unit 1
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	Global Rail Group, LLC, a subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FE on November 7, 2001
Green Valley	Green Valley Hydro, LLC, which owned hydro generating stations
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland and West Virginia electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	Signal Peak Energy, LLC, an indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

GLOSSARY OF TERMS, *Continued*

The following abbreviations and acronyms are used to identify frequently used terms in this report:

AAA	American Arbitration Association
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
ASU	Accounting Standards Update
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EMAAC	Eastern Mid-Atlantic Area Council of PJM
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan

GLOSSARY OF TERMS, *Continued*

ESTIP	Executive Short-Term Incentive Program
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCl	HydroChloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
KPI	Key Performance Indicator
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LED	Light Emitting Diode
LMP	Locational Marginal Price
LOC	Letter of Credit
LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MAAC	Mid-Atlantic Area Council of PJM
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System

GLOSSARY OF TERMS, *Continued*

NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
OTC	Over The Counter
OTTI	Other-Than-Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PTC	Price-to-Compare
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROE	Return on Equity
RPM	Reliability Pricing Model
RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB221	Amended Substitute Senate Bill No. 221

GLOSSARY OF TERMS, *Continued*

SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
TTS	Temporary Transaction Surcharge
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VRR	Variable Resource Requirement
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I

ITEM 1. BUSINESS

The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FE's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy and its subsidiaries are involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 miles of lines and two regional transmission operation centers.

Subsidiaries

FirstEnergy's revenues are primarily derived from electric service provided by its utility operating subsidiaries (OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE, and WP), ATSI and TrAIL, and the sale of energy and related products and services by its unregulated competitive subsidiaries, FES and AE Supply.

The Utilities' combined service areas encompass approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. The areas they serve have a combined population of approximately 13.5 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio. The area it serves has a population of approximately 2.3 million. OE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

OE owns all of Penn's outstanding common stock. Penn was organized under the laws of the Commonwealth of Pennsylvania in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business in the State of Ohio. Penn furnishes electric service to communities in 1,100 square miles of western Pennsylvania. The area it serves has a population of approximately 0.3 million. Penn complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.7 million. CEI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.7 million. TE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.7 million. JCP&L also has a 50% ownership interest (210 MW) in a hydroelectric generating facility. JCP&L complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and the NJBPU.

ME was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. ME provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.2 million. ME complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

PN was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. PN provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. PN, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in the Waverly, New York vicinity. PN complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NYPSC and PPUC.

PE was organized under the laws of the State of Maryland in 1923 and in the Commonwealth of Virginia in 1974. PE is authorized to do business in the Commonwealth of Virginia and the States of West Virginia and Maryland. PE owns property and does business as an electric public utility in those states. PE provides transmission and distribution services in portions of Maryland and West Virginia and provides transmission services in Virginia in an area totaling approximately 5,500 square miles. The area it serves has a population of approximately 0.9 million. PE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, MDPSC, VSCC, and WVPSC.

MP was organized under the laws of the State of Ohio in 1924 and owns property and does business as an electric public utility in the state of West Virginia. MP provides generation, transmission and distribution services in 13,000 square miles of northern West Virginia. The area it serves has a population of approximately 0.8 million. As of December 31, 2015, MP owned or contractually controlled 3,580 MWs of generation capacity that is supplied to its electric utility business. In addition, MP is contractually obligated to provide power to PE to meet its load obligations in West Virginia. MP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and WVPSC.

WP was organized under the laws of the Commonwealth of Pennsylvania in 1916 and owns property and does business as an electric public utility in that state. WP provides transmission and distribution services in 10,400 square miles of southwestern, south-central and northern Pennsylvania. The area it serves has a population of approximately 1.6 million. WP complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns major, high-voltage transmission facilities, which consist of approximately 7,800 circuit miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV in the PJM Region. ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, ATSI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

TrAIL was organized under the laws of the State of Maryland and the Commonwealth of Virginia in 2006. TrAIL was formed to finance, construct, own, operate and maintain high-voltage transmission facilities in the PJM Region and has several transmission facilities in operation, including a 500 kV transmission line extending approximately 150 miles from southwestern Pennsylvania through West Virginia to a point of interconnection with Virginia Electric and Power Company in northern Virginia. TrAIL plans, operates and maintains its transmission system and facilities in accordance with NERC reliability standards, and other applicable regulatory requirements. In addition, TrAIL complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, and applicable state regulatory authorities.

FES was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to retail and wholesale customers. FES also owns and operates, through its FG subsidiary, fossil generating facilities and owns, through its NG subsidiary, nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, organized under the laws of the State of Ohio in 1998, operates and maintains NG's nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and purchases the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

AE Supply was organized under the laws of the State of Delaware in 1999. AE Supply provides energy-related products and services to wholesale and retail customers. AE Supply also owns and operates fossil generating facilities and purchases and sells energy and energy-related commodities.

AGC was organized under the laws of the Commonwealth of Virginia in 1981. Approximately 59% of AGC is owned by AE Supply and approximately 41% by MP. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility (1,200 MW) and its connecting transmission facilities. AGC provides the generation capacity from this facility to AE Supply and MP.

FES, FG, NG, AE Supply and AGC comply with the regulations, orders, policies and practices prescribed by the SEC, FERC, and applicable state regulatory authorities. In addition, NG and FENOC comply with the regulations, orders, policies and practices prescribed by the NRC.

FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies.

Operating Segments

FirstEnergy's reportable operating segments are as follows: Regulated Distribution, Regulated Transmission and CES.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland.

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project.

The **CES** segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

Additional information regarding FirstEnergy's reportable segments is provided in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements. FES does not have separate reportable operating segments.

Competitive and Regulated Generation

As of February 16, 2016, FirstEnergy's generating portfolio consists of 16,952 MW of diversified capacity (CES — 13,162 MW and Regulated Distribution — 3,790 MW). Of the generation asset portfolio, approximately 9,218 MW (54.4%) consist of coal-fired capacity; 4,048 MW (23.9%) consist of nuclear capacity; 1,410 MW (8.3%) consist of hydroelectric capacity; 1,592 MW (9.4%) consist of oil and natural gas units; 496 MW (2.9%) consist of wind and solar power arrangements; and 188 MW (1.1%) consist of capacity entitlements to output from generation assets owned by OVEC. All units are located within PJM and sell electric energy, capacity and other products into the wholesale markets that are operated by PJM. Within CES' generation portfolio, 10,180 MW consist of FES' facilities that are operated by FENOC and FG (including entitlements from OVEC, wind and solar power arrangements), and except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates for which the corresponding output of these arrangements is available to FES through power sales agreements, are all owned directly by NG and FG. Another 2,982 MW of the CES' portfolio consists of AE Supply's facilities, including AE Supply's entitlement to 713 MW from AGC's Bath County, Virginia hydroelectric facility and 67 MW of AE Supply's 3.01% entitlement from OVEC's generation output. FES' generating facilities are concentrated primarily in Ohio and Pennsylvania and AE Supply's generating facilities are primarily located in Pennsylvania, West Virginia, Virginia and Ohio.

Within the Regulated Distribution segment's portfolio, 210 MW consist of JCP&L's 50% ownership interest in the Yards Creek hydroelectric facility in New Jersey; and 3,580 MW consist of MP's facilities, including 487 MW from AGC's Bath County, Virginia hydroelectric facility that MP partially owns and 11 MW of MP's 0.49% entitlement from OVEC's generation output. MP's facilities are concentrated primarily in West Virginia.

Utility Regulation

State Regulation

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

Federal Regulation

With respect to their wholesale services and rates, the Utilities, AE Supply, ATSI, AGC, FES, FG, NG, PATH and TrAIL are subject to regulation by FERC. Under the FPA, FERC regulates rates for interstate wholesale sales, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of ATSI, JCP&L, ME, MP, PE, PN, WP and TrAIL are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff. See FERC Matters below.

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities, AE Supply, FES, FG, NG, FGMUC, Buchanan Generation and Green Valley each have been authorized by FERC to sell wholesale power in interstate commerce at market rates and have a market-based rate tariff on file with FERC, although major wholesale purchases remain subject to regulation by the relevant state commissions. As a condition to selling electricity on a wholesale basis at market-based rates, the Utilities, AE Supply, FES, FG, NG, FGMUC, Buchanan Generation and Green Valley, like other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter. However, consistent with its historical practice, FERC has granted AE Supply, FES, FG, NG, FGMUC, Buchanan Generation and Green Valley a waiver from certain reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, FERC also granted AE Supply, FES, FG, NG, FGMUC, Buchanan Generation and Green Valley blanket authority to issue securities and assume liabilities under Section 204 of the FPA.

The nuclear generating facilities owned and leased by NG, OE and TE, and operated by FENOC, are subject to extensive regulation by the NRC. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security, environmental and radiological aspects of those stations. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the licenses. FENOC is the licensee for the operating nuclear plants and has direct compliance responsibility for NRC matters. FES controls the economic dispatch of NG's plants. See Nuclear Regulation below.

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, NG, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

Regulatory Accounting

The Utilities, AGC, ATSI, PATH and TrAIL recognize, as regulatory assets and regulatory liabilities, costs which FERC and the various state utility commissions, as applicable, have authorized for recovery/return from/to customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and regulatory liabilities would have been charged to income as incurred. All regulatory assets and liabilities are expected to be recovered/returned from/to customers. Based on current ratemaking procedures, the Utilities, AGC, ATSI, PATH and TrAIL continue to collect cost-based rates for their transmission and distribution services and, in the case of PATH, for its abandoned plant, which remains regulated; accordingly, it is appropriate that the Utilities, AGC, ATSI, PATH and TrAIL continue the application of regulatory accounting to those operations. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded net regulatory assets or liabilities are removed from the balance sheet in accordance with GAAP.

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, AGC, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.

Maryland Regulatory Matters

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

New Jersey Regulatory Matters

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET.

On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

Ohio Regulatory Matters

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;
- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015.The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;

- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

Pennsylvania Regulatory Matters

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

West Virginia Regulatory Matters

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015 and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

FERC Matters

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings.FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

Capital Requirements

The centerpiece of FirstEnergy's regulated investment strategy is the *Energizing the Future* transmission expansion plan, with an initial phase that includes $4.2 billion in investments from 2014 to 2017 to modernize FirstEnergy's transmission system. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be $1 billion. Planned capital expenditures for 2016 for Regulated Distribution, CES, and Corporate/Other will be dependent upon the outcome of the Ohio Companies' ESP IV and remain subject to Board approval.

Actual capital expenditures for 2015 by operating company and reportable segment are shown in the following tables. Such costs include expenditures for the improvement of existing facilities and for the construction of transmission lines, distribution lines and substations, and other assets.

Operating Company	2015 Actual[1]	2015 Pension/ OPEB Mark-to-Market Capital Costs	2015 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs
		(In millions)	
OE	$ 198	$ 37	$ 161
Penn	60	8	52
CEI	122	(3)	125
TE	45	(1)	46
JCP&L	303	45	258
ME	120	20	100
PN	163	23	140
MP	248	(4)	252
PE	99	(2)	101
WP	137	—	137
ATSI	617	—	617
TrAIL	212	—	212
FES	512	1	511
AE Supply	82	—	82
Other subsidiaries	98	3	95
Total	$ 3,016	$ 127	$ 2,889

Reportable Segment	2015 Actual[1]	2015 Pension/ OPEB Mark-to-Market Capital Costs	2015 Actual Excluding Pension/OPEB Mark-to-Market Capital Costs
		(In millions)	
Regulated Distribution	$ 1,290	$ 113	$ 1,177
Regulated Transmission	986	10	976
CES	626	4	622
Corporate/Other	114	—	114
Total	$ 3,016	$ 127	$ 2,889

(1) Includes an increase of approximately $127 million related to the capital component of the non-cash pension and OPEB mark-to-market adjustment.

The following table presents scheduled debt repayments for outstanding long-term debt as of December 31, 2015, excluding capital leases for the next five years. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

	2016	2017-2020	Total
		(In millions)	
FirstEnergy	$ 1,039	$ 6,934	$ 7,973
FES	$ 414	$ 1,762	$ 2,176

The following tables display consolidated operating lease commitments as of December 31, 2015.

Operating Leases	FirstEnergy Lease Payments	PNBV[1]	Net
		(In millions)	
2016	$ 197	$ 13	$ 184
2017	122	3	119
2018	135	—	135
2019	116	—	116
2020	91	—	91
Years thereafter	1,438	—	1,438
Total minimum lease payments	$ 2,099	$ 16	$ 2,083

(1) PNBV purchased a portion of the lease obligation bonds associated with certain sale and leaseback transactions. These arrangements effectively reduce lease costs related to those transactions.

Operating Leases	FES
	(In millions)
2016	$ 131
2017	82
2018	101
2019	97
2020	68
Years thereafter	1,315
Total minimum lease payments	$ 1,794

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest payments, dividend payments, and contributions to its pension plan. During 2015, FirstEnergy received $630 million of cash dividends and capital returned from its subsidiaries and paid $607 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2016 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions. Additionally in 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions. In the future, FirstEnergy may consider equity issuances to fund capital requirements in the regulated operations.

Any financing plans by FirstEnergy, including the issuance of equity, refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such issuances, financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was $4.1 billion.

In January 2016, FirstEnergy's Board of Directors declared a quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2016, to shareholders of record at the close of business on February 5, 2016. This dividend equates to an indicated annual dividend of $1.44 per share and is consistent with the dividends declared in 2015.

Nuclear Operating Licenses

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

The following table summarizes the current operating license expiration dates for FES' nuclear facilities in service.

Station	In-Service Date	Current License Expiration
Beaver Valley Unit 1	1976	2036
Beaver Valley Unit 2	1987	2047
Perry	1986	2026
Davis-Besse	1977	2037

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $15 million (NG-$15 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $83 million (NG-$81 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

Environmental Matters

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield's Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2015 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

Fuel Supply

FirstEnergy currently has coal contracts with various terms to acquire approximately 21.5 million tons of coal for the year 2016 which is approximately 100% of its estimated 2016 coal requirements. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, and West Virginia. The contracts expire at various times through 2028. See Environmental Matters for additional information pertaining to the impact of increased environmental regulations on coal supply and transportation contracts applicable to certain deactivated coal-fired generating units.

FirstEnergy has contracts for all uranium requirements through 2018 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2018 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. A portion of enrichment requirements is also contracted for through 2024. Fabrication services for fuel assemblies are contracted for both Beaver Valley units through 2020 and Davis-Besse through 2025 and through the current operating license period for Perry.

On-site spent fuel storage facilities are currently adequate for all FENOC operating units. An on-site dry cask storage facility has been constructed at Beaver Valley sufficient to extend spent fuel storage capacity through the end of current operating licenses at Beaver Valley Unit 1 and Beaver Valley Unity 2. Davis-Besse is planning to resume dry cask storage operations in 2017 which will extend on-site spent fuel storage capacity through the end of its recently extended operating license. Perry completed plant modification for dry cask storage in 2012, loaded spent fuel into dry cask storage in 2012 and 2014 (referred to as a loading campaign), and has planned to conduct additional dry cask storage loading campaigns that will provide for sufficient spent fuel storage capacity through 2046 (end of current operating license plus a 20-year operating license extension).

The Federal Nuclear Waste Policy Act of 1982 provided for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NG has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The DOE submitted the license application for Yucca Mountain to the NRC on June 3, 2008. The current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies has been performed.

In light of this uncertainty, FirstEnergy has made arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

Natural gas demand at the combined cycle and peaking units is forecasted at approximately 30 million cubic feet in 2016. Fuel oil and natural gas are also used to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to average approximately 9 million gallons per year over the next five years.

System Demand

The 2015 maximum hourly demand for each of the Utilities was:

- OE—5,391 MW on July 29, 2015;
- Penn—983 MW on July 29, 2015;
- CEI—4,057 MW on August 19, 2015;
- TE—2,149 MW on September 8, 2015;
- JCP&L—5,789 MW on July 20, 2015;
- ME—2,770 MW on July 20, 2015;
- PN—3,024 MW on February 19, 2015;
- MP—2,031 MW on January 7, 2015;
- PE—3,631 MW on February 20, 2015; and
- WP—3,942 MW on February 20, 2015.

Supply Plan

Regulated Commodity Sourcing

Certain of the Utilities have default service obligations to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L's default service or BGS supply is secured through a statewide competitive procurement process approved by the NJBPU. Default service for the Ohio Companies, Pennsylvania Companies and PE's Maryland jurisdiction are provided through a competitive procurement process approved by the PUCO (under the ESP), PPUC (under the DSP) and MDPSC (under the SOS), respectively. If any supplier fails to deliver power to any one of those Utilities' service areas, the Utility serving that area may need to procure the required power in the market in their role as a LSE. West Virginia electric generation continues to be regulated by the WVPSC.

Unregulated Commodity Sourcing

The CES segment, through FES and AE Supply, primarily provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES and AE Supply provide the power requirements of their competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

FES and AE Supply have retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey, serving both affiliated and non-affiliated companies. FES and AE Supply provide energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. Geographically, most of FES' and AE Supply's obligations are in the PJM market area where all of their respective generation facilities are located.

Regional Reliability

All of FirstEnergy's facilities are located within the PJM Region and operate under the reliability oversight of a regional entity known as RFC. This regional entity operates under the oversight of NERC in accordance with a delegation agreement approved by FERC.

Competition

Within FirstEnergy's Regulated Distribution segment, generally there is no competition for electric distribution service in the Utilities' respective service territories in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. Additionally, there has traditionally been no competition for transmission service in PJM. However, pursuant to FERC's Order No. 1000 and subject to state and local siting and permitting approvals, non-incumbent developers now can compete for certain PJM transmission projects in the service territories of FirstEnergy's Regulated Transmission segment. This could result in additional competition to build transmission facilities in the Regulated Transmission segment's service territories while also allowing the Regulated Transmission segment the opportunity to seek to build facilities in non-incumbent service territories.

FirstEnergy's CES segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, through FES and AE Supply. In these markets, the CES segment competes: (1) to provide retail generation service directly to end users; (2) to provide wholesale generation service to utilities, municipalities and co-operatives, which, in turn, resell to end users; and (3) in the wholesale market.

Seasonality

The sale of electric power is generally a seasonal business and weather patterns can have a material impact on FirstEnergy's operating results. Demand for electricity in our service territories historically peaks during the summer and winter months, with market prices also generally peaking at those times. Accordingly, FirstEnergy's annual results of operations and liquidity position may depend disproportionately on its operating performance during the summer and winter. Mild weather conditions may result in lower power sales and consequently lower earnings.

Research and Development

The Utilities, FES, FG, FENOC and ATSI participate in the funding of EPRI, which was formed for the purpose of expanding electric R&D under the voluntary participation of the nation's electric utility industry — public, private and cooperative. Its goal is to mutually benefit utilities and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. EPRI conducts research on all aspects of electric power production and use, including fuels, generation, and delivery, efficient management of energy use, environmental effects and energy analysis. The majority of EPRI's R&D programs and projects are directed toward business solutions and their applications to problems facing the electric utility industry.

FirstEnergy participates in other initiatives with industry R&D consortiums and universities to address technology needs for its various business units. Participation in these consortiums helps the company address research needs in areas such as plant operations and maintenance, major component reliability, environmental controls, advanced energy technologies, and transmission and distribution system infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

Executive Officers as of February 16, 2016

Name	Age	Positions Held During Past Five Years	Dates
G. D. Benz	56	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	2012-2015
L. M. Cavalier	64	Chief Human Resources Officer (B)	2015-present
		Senior Vice President, Human Resources (B)	*-2015
D. M. Chack	65	Senior Vice President, Marketing and Branding (B)	2015-present
		President, Ohio Operations (B)	2011-2015
		Vice President (C)	2011-2015
		Regional President (M)	*-2011
M. J. Dowling	51	Senior Vice President, External Affairs (B)	2011-present
		Vice President, External Affairs (B)	*-2011
B. L. Gaines	62	Senior Vice President, Corporate Services and Chief Information Officer (B)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	*-2011
C. E. Jones	60	President and Chief Executive Officer (A)(B)	2015-present
		Chief Executive Officer (F)	2015-present
		Executive Vice President & President, FirstEnergy Utilities (A)(B)	2014
		Senior Vice President & President, FirstEnergy Utilities (B)	*-2013
		President (H)(I)	2011-2015
		President (C)(D)(L)	*-2015
		Senior Vice President & President, FirstEnergy Utilities (A)	*-2011
J. H. Lash	65	Executive Vice President & President, FE Generation (A)(B)	2015-present
		President, FE Generation (B)	2011-2015
		President (G)(J)	2011-present
		Chief Nuclear Officer (F)	2011-2012
		President and Chief Nuclear Officer (F)	*-2011
		President, FirstEnergy Nuclear Operating Company (B)	*-2011
C. D. Lasky	53	Senior Vice President, Human Resources (B)	2015-present
		Vice President, Fossil Operations (J)	2014-2015
		Vice President, Fossil Operations & Engineering (J)	2014
		Vice President (G)	2011-2015
		Vice President, Fossil Fleet Operations (J)	2011-2013
		Vice President (J)	*-2011
		Vice President, Fossil Operations (E)	*-2011
J. F. Pearson	61	Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2015-present
		Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-2015
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(J)(L)	*-2012
		Vice President and Treasurer (G)(H)(I)	2011-2012
D. R. Schneider	54	President (E)	*-present
S. E. Strah	52	Senior Vice President & President, FirstEnergy Utilities (B)	2015-present
		President (C)(D)(H)(I)(L)	2015-present
		Vice President, Distribution Support (B)	2011-2015
		Regional President (K)	*-2011
K. J. Taylor	42	Vice President, Controller and Chief Accounting Officer (A)(B)	2013-present
		Vice President and Controller (C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-present
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012-2013
		Assistant Controller (A)(B)(C)(D)(L)	*-2012
		Assistant Controller (H)(I)	2011-2012
		Assistant Controller (E)(F)(G)(J)	2012
L. L. Vespoli	56	Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2014-present
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(J)(L)	*-2013
		Executive Vice President and General Counsel (G)(H)(I)	2011-2013

* Indicates position held at least since January 1, 2011
(A) Denotes executive officer of FE
(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN and Penn
(E) Denotes executive officer of FES
(F) Denotes executive officer of FENOC
(G) Denotes executive officer of AGC
(H) Denotes executive officer of MP, PE and WP
(I) Denotes executive officer of TrAIL and FET
(J) Denotes executive officer of FG
(K) Denotes executive officer of OE
(L) Denotes executive officer of ATSI
(M) Denotes executive officer of CEI

Employees

As of December 31, 2015, FirstEnergy's subsidiaries had 15,781 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	4,179	614
OE	1,087	713
CEI	945	635
TE	331	237
Penn	190	137
JCP&L	1,378	1,082
ME	658	501
PN	756	503
FES	125	—
FG	1,738	1,070
FENOC	2,653	1,186
MP	589	382
PE	460	283
WP	692	448
Total	**15,781**	**7,791**

As of December 31, 2015, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 6,900 of FirstEnergy's employees. There are 22 CBAs between FirstEnergy's subsidiaries and its unions, most of which have three year terms. In 2015, certain of FirstEnergy's subsidiaries reached new agreements on CBAs with four different IBEW locals, covering approximately 1,680 employees. These contracts will expire in 2018 and 2019. Additionally, in early 2016, PN reached a new agreement with IBEW local 459, covering approximately 425 employees, which will expire in 2021.

On July 1, 2015, IBEW Local 29, which represents approximately 17 employees at the Beaver Valley nuclear plant, ratified a new agreement that will expire September 30, 2018. On October 14, 2015, IBEW Local 777 CC, which represents approximately 161 call center employees in Reading, PA, ratified a new agreement that will expire on October 31, 2018. On November 12, 2015, IBEW Local 1289, which represents approximately 1,086 employees at JCP&L, ratified a new agreement that will expire on October 31, 2018. On November 24, 2015, IBEW Local 245, which represents approximately 416 employees of TE, the Davis-Besse nuclear plant and the Bay Shore generating station, ratified a new agreement that will expire on October 31, 2019.

The agreement with IBEW Local 272, which represents approximately 238 employees at the Bruce Mansfield Plant, expired on February 15, 2014. On October 27, 2015, following nearly two years of bargaining, FirstEnergy declared impasse and implemented terms and conditions of employment from its last comprehensive offer to settle. FirstEnergy continues to engage in negotiations with IBEW Local 272, and work continuation plans are in place in the event of a work stoppage. The agreement with UWUA Local 270, which represents approximately 76 employees at the Perry Nuclear Plant expired on November 16, 2015. The parties continue to negotiate for a new contract and work continuation plans are in place in the event of a work stoppage.

FirstEnergy Website and Other Social Media Sites and Applications

Each of the registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through the "Investors" page of FirstEnergy's Internet website at www.firstenergycorp.com. The public may read and copy any reports or other information that the registrants file 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 SEC's public reference room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services and the website maintained by the SEC at www.sec.gov.

These SEC filings are posted on FirstEnergy's website as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of FirstEnergy's Internet website and recognize FirstEnergy's Internet website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to the website by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet website or through push alerts from FirstEnergy Investor Relations apps for Apple Inc.'s iPad® and iPhone® devices, which can be installed for free at the Apple® online store. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under Regulation FD. Information contained on FirstEnergy's Internet website, posted on FirstEnergy's Facebook® page or disseminated through Twitter®, and any corresponding applications, shall not be deemed incorporated into, or to be part of, this report.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management of each Registrant regularly evaluates the most significant risks of the Registrants' businesses and reviews those risks with the FirstEnergy Board of Directors or appropriate Committees of the Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we currently consider material. Additional information on risk factors is included in "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Registrant and Subsidiaries" and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results.

Risks Related to Business Operations

We Have Taken a Series of Actions to Focus Our Growth on Our Regulated Operations. Whether This Will Deliver the Desired Result is Subject to Certain Risks Which Could Adversely Affect Profitability and our Financial Condition in the Future

We focus on capitalizing on investment opportunities available to our regulated operations - particularly in transmission - as we focus on delivering enhanced customer service and reliability. The success of these efforts will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments may include: (1) whether the investments are included in PJM's RTEP; (2) FERC's evolving policies with respect to incentive rates for transmission assets; (3) FERC's evolving policies with respect to the base ROE component of transmission rates, as articulated in FERC's Opinion No. 531 and related orders; (4) consideration of the objections of those who oppose such investments and their recovery; and (5) timely development, construction, and operation of the new facilities.

The success of these efforts will also depend, in part, on our achieving positive outcomes in the ESP IV before the PUCO and any future distribution rate cases and transmission rate filings. Any denial of, or delay in, the approval of ESP IV or any future distribution or transmission rate request could restrict us from fully recovering our cost of service, may impose risk on operations, and could have a material adverse effect on our regulatory strategy. In addition, CES' continued operation of the generating units included in the PPA portion of the ESP IV is uncertain.

Our efforts also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that our efforts to reflect a more regulated business profile will deliver the desired result which could adversely affect our future profitability and financial condition.

We Are Subject to Risks Arising from the Operation of Our Power Plants and Transmission and Distribution Equipment

Operation of generation, transmission and distribution facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, human error in operations or maintenance, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental requirements and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operation and maintenance costs, purchased power costs and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our sales obligations. Moreover, if we were unable to perform under contractual obligations, including, but not limited to, our coal and coal transportation contracts, penalties or liability for damages could result.

FES, FG, OE and TE are exposed to losses under their applicable sale-leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless. Although we believe these types of events are unlikely to occur, FES, FG, OE and TE have a maximum exposure to loss under those provisions of approximately $1.2 billion for FES, $368 million for OE and $192 million for TE. In addition, new and certain existing environmental requirements may force us to shut down such generating facilities or change their operating status, either temporarily or permanently, if we are unable to comply with such environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are unreasonable.

Failure to Provide Safe and Reliable Service and Equipment Could Result in Serious Injury or Loss of Life That May Harm Our Business Reputation and Adversely Affect our Operating Results

We are obligated to provide safe and reliable service and equipment in our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. However, our employees, contractors and the general public may be exposed to dangerous environments, due to the nature of our operations. Failure to provide safe and reliable service and equipment due to a number of factors, including, equipment failure, accidents and weather, could result in serious injury or loss of life that may harm our business reputation and adversely affect our operating results through reduced revenues and increased capital and operating costs and the imposition of penalties/fines or other adverse regulatory outcomes.

Continued Pressure on Commodity Prices Including, but Not Limited to Natural Gas, Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive retail and wholesale markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Competition and changes in the short or long-term market price of electricity, which are affected by changes in other commodity costs and other factors including, but not limited to, weather, energy efficiency mandates, DR initiatives and deactivations and retirements at power production facilities, may impact our results of operations and financial position by decreasing sales margins or increasing the amount we pay to purchase power to satisfy our sales obligations in the states in which we do business. We are exposed to risk from the volatility of the market price of natural gas. Our ability to sell at a profit is highly dependent on the price of natural gas. With low natural gas prices, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices, so the margins we realize from sales will be lower and, on occasion, we may curtail or cease operation of marginal plants. The availability of natural gas and issues related to its accessibility may have a long-term material impact on the price of natural gas. In addition, deterioration or weakness in the global economy has led to lower international demand for coal, oil and natural gas, which has lowered fossil fuel prices and may continue to put downward pressure on electricity prices.

We Are Exposed to Operational, Price and Credit Risks Associated With Marketing and Selling Products in the Power Markets That We Do Not Always Completely Hedge Against

We purchase and sell power at the wholesale level under market-based rate tariffs authorized by FERC, and also enter into agreements to sell available energy and capacity from our generation assets. If we are unable to deliver firm capacity and energy under these agreements, we may be required to pay damages, including significant penalties under PJM's Capacity Performance market reform. These damages would generally be based on the difference between the market price to acquire replacement capacity or energy and the contract price of the undelivered capacity or energy. Depending on price volatility in the wholesale energy markets, such damages and penalties could be significant. A single outage could result in penalties that exceed capacity revenues for a given unit in a given year. Extreme weather conditions, unplanned power plant outages, transmission disruptions, and other factors could affect our ability to meet our obligations, or cause increases in the market price of replacement capacity and energy.

We attempt to mitigate risks associated with satisfying our contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy our net firm sales contracts and, when necessary, by purchasing firm transmission service. We also routinely enter into contracts, such as fuel and power purchase and sale commitments, to hedge exposure to fuel requirements and other energy-related commodities. We may not, however, hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position could be negatively affected. In addition, these risk management related contracts could require the posting of additional collateral in the event market prices or market conditions change.

The Use of Derivative Contracts by Us to Mitigate Risks Could Result in Financial Losses That May Negatively Impact Our Financial Results

We use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. Also, we could recognize financial losses as a result of volatility in the market value of these contracts if a counterparty fails to perform or if there is limited liquidity of these contracts in the market.

Financial Derivatives Reforms Could Increase Our Liquidity Needs and Collateral Costs and Impose Additional Regulatory Burdens

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law in July 2010 with the primary objective of increasing oversight of the United States financial system, including the regulation of most financial transactions, swaps and derivatives. Dodd-Frank requires CFTC and SEC rulemaking to implement such provisions. Although the CFTC and the SEC have completed certain of their rulemaking, other rulemaking remains.

We rely on the OTC derivative markets as part of our program to hedge the price risk associated with our power portfolio. As a qualified end-user, we are required to comply with regulatory obligations under Dodd-Frank, which includes record-keeping, reporting requirements and the clearing of some transactions that we would otherwise enter into over-the-counter and the posting of margin. Also, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swap market to decrease. These rules could impede our ability to meet our hedge targets in a cost-effective manner. FirstEnergy cannot predict the future impact Dodd-Frank rulemaking will have on its results of operations, cash flows or financial position.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit, Are by Their Very Nature Subject to Uncertainties, and We Could Suffer Economic Losses Despite Our Efforts to Manage and Mitigate Our Risks

We attempt to mitigate the market risk inherent in our energy, fuel and debt positions. Procedures have been implemented to enhance and monitor compliance with our risk management policies, including validation of transaction and market prices, verification of risk and transaction limits, sensitivity analysis and daily portfolio reporting of various risk measurement metrics. Nonetheless, we cannot economically hedge all of our exposure in these areas and our risk management program may not operate as planned. For example, actual electricity and fuel prices may be significantly different or more volatile than the historical trends and assumptions reflected in our analyses. Also, our power plants might not produce the expected amount of power during a given day or time period due to weather conditions, technical problems or other unanticipated events, which could require us to make energy purchases at higher prices than the prices under our energy supply contracts, and also to pay significant penalties under PJM's Capacity Performance market reform. In addition, the amount of fuel required for our power plants during a given day or time period could be more than expected, which could require us to buy additional fuel at prices less favorable than the prices under our fuel contracts. As a result, actual events may lead to greater losses or costs than our risk management positions were intended to hedge.

Our risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the creditworthiness of counterparties, future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be adversely affected if the judgments and assumptions underlying those calculations prove to be inaccurate.

Nuclear Generation Involves Risks that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning, Which Could Have a Material Adverse Effect on Our Business, Results of Operations and Financial Condition

We are subject to the risks of nuclear generation, including but not limited to the following:

- the potential harmful effects on the environment and human health, including loss of life, resulting from unplanned radiological releases associated with the operation of our nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations, including any incidents of unplanned radiological release, or those of others in the United States;
- uncertainties with respect to contingencies and assessments if insurance coverage is inadequate; and
- uncertainties with respect to the technological and financial aspects of spent fuel storage and decommissioning nuclear plants, including but not limited to, waste disposal at the end of their licensed operation and increases in minimum funding requirements or costs of decommissioning.

The NRC has broad authority under federal law to impose licensing security and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Also, a serious nuclear incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit. See "Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Affect Our Business and Financial Condition" below and Note 15, Commitments, Guarantees and Contingencies - Environmental Matters of the Combined Notes to the Consolidated Financial Statements. Any one of these risks relating to our nuclear generation could have a material adverse effect on our business, results of operations and financial condition.

The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings, Involving Our Business, or That of One or More of Our Operating Subsidiaries, is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Position and Results of Operations

We are involved in a number of litigation, arbitration, mediation, and similar proceedings including, but not limited to, such proceedings relating to certain fuel and fuel transportation contracts as described in Note 15, Commitments, Guarantees, and Contingencies, of the Combined Notes to the Consolidated Financial Statements. These and other matters may divert financial and management resources that would otherwise be used to benefit our operations. Further, no assurances can be given that the resolution of these matters will be favorable to us. If certain matters were ultimately resolved unfavorably to us, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have a material adverse impact on our financial position and operating results.

We Have a Significant Percentage of Coal-Fired Generation Capacity Which Exposes Us to Risk from Regulations Relating to Coal and CCRs

Approximately 55% of FirstEnergy's generation fleet capacity is coal-fired. Historically, coal-fired generating plants have greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to air emissions, including GHGs, and CCR disposal, than other types of electric generation facilities. In December 2014, the EPA finalized regulations for CCRs (non-hazardous waste), establishing national standards for the safe disposal of CCRs from electric generating plants. In August 2015, the EPA finalized the CPP requiring reductions in GHG emissions from existing electric generating plants. These legal requirements and any future initiatives could impose substantial additional costs and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements.

Capital Market Performance and Other Changes May Decrease the Value of Pension Fund Assets, Decommissioning and Other Trust Funds, Which Then Could Require Significant Additional Funding

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generation facilities and under pension and other postemployment benefit plans. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission nuclear generating stations, to pay future pension and other obligations, requires significant judgment and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or that negatively impact the discount rate and increase the present value of liabilities may have significant impacts on the value of the pension, decommissioning and other trust funds, which could negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets

Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. FERC has authority to impose penalties up to and including $1 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by FERC, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the perceived potential for exercise of market power and to ensure the markets function appropriately. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, PJM may direct our transmission-owning affiliates to build new transmission facilities to meet PJM's reliability requirements or to provide new or expanded transmission service under the PJM Tariff.

We Rely on Transmission and Distribution Assets That We Do Not Own or Control to Deliver Our Wholesale Electricity. If Transmission is Disrupted, Including Our Own Transmission, or Not Operated Efficiently, or if Capacity is Inadequate, Our Ability to Sell and Deliver Power May Be Hindered

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity we sell. If transmission is disrupted (as a result of weather, natural disasters or other reasons) or not operated efficiently by ISOs and RTOs, in applicable markets, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered, or we may be unable to sell products on the most favorable terms. In addition, in certain of the markets in which we operate, we may be required to pay for congestion costs if we schedule delivery of power between congestion zones during periods of high demand. If we are unable to hedge or recover such congestion costs in retail rates, our financial results could be adversely affected.

Demand for electricity within our Utilities' service areas could stress available transmission capacity requiring alternative routing or curtailing electricity usage that may increase operating costs or reduce revenues with adverse impacts to our results of operations.

In addition, as with all utilities, potential concerns over transmission capacity could result in PJM or FERC requiring us to upgrade or expand our transmission system, requiring additional capital expenditures that we may be unable to recover fully or at all.

FERC requires wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, it is possible that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electricity as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets or whether ISOs or RTOs in applicable markets will operate the transmission networks, and provide related services, efficiently.

Disruptions in Our Fuel Supplies and Changes in Our Fuel Transportation Needs Could Adversely Affect Our Relationships With Suppliers, Our Ability to Operate Our Generation Facilities or Lead to Business Disputes, Any of Which May Adversely Impact Financial Results

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations. Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. We have long-term contracts in place for a majority of our coal supply and transportation needs, one of which runs through 2028 and certain of which relate to deactivated plants. We have asserted force majeure defenses for delivery shortfalls under certain of these agreements relating to our deactivated plants. One such agreement relates to the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain deactivated coal-fired power plants owned by FG, and this agreement is now in arbitration. Another such agreement relates to the delivery of 2.5 million tons annually through 2025 to an operating plant as well as a deactivated plant. In addition, in one coal supply agreement, FirstEnergy, through a subsidiary, has also asserted termination rights effective in 2015 and is in litigation with the counterparty.

We can provide no assurance that negotiations with counterparties, or any litigation or arbitration, will be favorably resolved. An adverse resolution of any of these material matters could have a material adverse impact on our financial position and results of operations. In addition, we may from time to time enter into new contracts, or renegotiate certain of these contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. In addition, if prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Temperature Variations as well as Weather Conditions or other Natural Disasters Could Have a Negative Impact on Our Results of Operations and Demand Significantly Below or Above Our Forecasts Could Adversely Affect Our Energy Margins

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snowstorms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period and could have an adverse effect on our financial condition and results of operations.

Customer demand could change as a result of severe weather conditions or other circumstances over which we have no control. We satisfy our electricity supply obligations through a portfolio approach of providing electricity from our generation assets, contractual relationships and market purchases. A significant increase in demand could adversely affect our energy margins if we are required to provide the energy supply to fulfill this increased demand at fixed rates, which we expect would remain below the wholesale prices at which we would have to purchase the additional supply if needed or, if we had available capacity, the prices at which we could otherwise sell the additional supply. A significant decrease in demand, resulting from factors including but not limited to increased customer shopping, more stringent energy efficiency mandates and increased DR initiatives could cause a decrease in the market price of power. Accordingly, any significant change in demand could have a material adverse effect on our results of operations and financial position.

We Are Subject to Financial Performance Risks Related to Regional and General Economic Cycles and also Related to Heavy Manufacturing Industries such as Automotive and Steel

Our business follows economic cycles. Economic conditions impact the demand for electricity and declines in the demand for electricity will reduce our revenues. The regional economy in which our Utilities operate is influenced by conditions in industries in our business territories, e.g. shale gas, automotive, chemical, steel and other heavy industries, and as these conditions change, our revenues will be impacted. Additionally, the primary market areas of our CES segment overlap, to a large degree, with our Utilities' territories and hence its revenues are substantially impacted by the same economic conditions, such as changes in industrial demand.

The Recognition of Impairments of Goodwill, Long-Lived Assets, Including Certain Investments, Could Have an Adverse Effect on Our Results of Operations

We have approximately $6.4 billion of goodwill on our consolidated balance sheet as of December 31, 2015, of which $800 million is attributable to our CES segment. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. Key assumptions incorporated in the estimated cash flows used for the impairment analysis requiring significant management judgment include: discount rates, growth rates, future energy and capacity pricing, projected operating income, changes in working capital, projected capital expenditures, projected funding of pension plans, expected results of future rate proceedings, the impact of pending carbon and other environmental legislation and terminal multiples. Although the annual goodwill impairment test in 2015 resulted in a conclusion that goodwill was not impaired, the fair value of the CES reporting unit exceeded its carrying value by only approximately 10%. We are unable to predict whether future impairment charges to goodwill may be necessary.

In addition, we also review our long-lived assets and investments for impairment when circumstances indicate the carrying value of these assets may not be recoverable. For example, in 2015, we recorded a $362 million non-cash, pre-tax impairment charge associated with our investment in Global Holding, primarily as a result of distress in the coal market and industry. We are unable to predict whether impairments of one or more of our long-lived assets or investments may occur in the future. The actual timing and amounts of any impairments to goodwill, or long-lived assets in the future would depend on many factors, including interest rates, sector market performance, our capital structure, natural gas or other commodity prices, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable acquisitions, environmental regulations and other factors. A determination that goodwill, a long-lived asset, or other investments are impaired would result in a non-cash charge that could materially adversely affect our results of operations and capitalization.

We Face Certain Human Resource Risks Associated with Potential Labor Disruptions and/or With the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements

We must find ways to balance the retention of our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Further, a significant number of our physical workforce are represented by unions and while we believe that our relations with our employees are generally fair, we cannot provide assurances that the company will be completely free of labor disruptions such as work stoppages, work slowdowns, union organizing campaigns, strikes, lockouts or that any labor disruption will be favorably resolved. Mitigating these risks could require additional financial commitments and the failure to retain or attract trained and qualified labor could have an adverse effect on our business.

Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. However, we expect to continue to face increased cost pressures related to operation and maintenance expenses, including in the areas of health care and pension costs. We have experienced health care cost inflation in recent years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, discount rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. While we anticipate that our operation and maintenance expenses will continue to increase, if actual results differ materially from our assumptions, our costs could be significantly higher than expected which could adversely affect our future earnings and liquidity.

Our Results May be Adversely Affected by the Volatility in Pension and OPEB Expenses

FirstEnergy recognizes in income the change in the fair value of plan assets and net actuarial gains and losses for its defined Pension and OPEB plans. This adjustment is recognized in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, which could result in greater volatility in pension and OPEB expenses and may materially impact our results of operations.

Cyber-Attacks, Data Security Breaches and Other Disruptions to Our Information Technology Systems Could Compromise Our Business Operations, Critical and Proprietary Information and Employee and Customer Data, Which Could Have a Material Adverse Effect on Our Business, Financial Condition and Reputation

In the ordinary course of our business, we use and are dependent upon information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our generation, transmission and distribution services. Additionally, we store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks. The secure maintenance of information and information technology systems is critical to our operations.

Over the last several years, there has been an increase in the frequency of cyber-attacks by terrorists, hackers, international activist organizations, countries and individuals. These and other unauthorized parties may attempt to gain access to our network systems or facilities, or those of third parties with whom we do business in many ways, including directly through our network infrastructure or through fraud, trickery, or other forms of deceiving our employees, contractors and temporary staff. Additionally, our information and information technology systems may be increasingly vulnerable to data security breaches, damage and/or interruption due to viruses, human error, malfeasance, faulty password management or other malfunctions and disruptions. Further, hardware, software, or applications we develop or procure from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information and/or security.

Despite security measures and safeguards we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to such attacks as a result of the rapidly evolving and increasingly sophisticated means by which attempts to defeat our security measures and gain access to our information technology systems may be made. Also, we may be at an increased risk of a cyber-attack and/or data security breach due to the nature of our business.

Any such cyber-attack, data security breach, damage, interruption and/or defect could: (i) disable our generation, transmission (including our interconnected regional transmission grid) and/or distribution services for a significant period of time; (ii) delay development and construction of new facilities or capital improvement projects; (iii) adversely affect our customer operations; (iv) corrupt data; and/or (v) result in unauthorized access to the information stored in our data centers and on our networks, including, company proprietary information, supplier information, employee data, and personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in economic loss and liability and harmful effects on the environment and human health, including loss of life. Additionally, because our generation, transmission and distribution services are part of an interconnected system, disruption caused by a cybersecurity incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our operations.

Although we maintain cyber insurance and property and casualty insurance, there can be no assurance that liabilities or losses we may incur will be covered under such policies or that the amount of insurance will be adequate. Further, as cyber threats become more difficult to detect and successfully defend against, there can be no assurance that we can implement adequate preventive measures, accurately assess the likelihood of a cyber-incident or quantify potential liabilities or losses. Also, we may not discover any data security breach and loss of information for a significant period of time after the data security breach occurs. For all of these reasons, any such cyber incident could result in significant lost revenue, the inability to conduct critical business functions and serve customers for a significant period of time, the use of significant management resources, legal claims or proceedings, regulatory penalties, increased regulation, increased capital costs, increased protection costs for enhanced cyber security systems or personnel, damage to our reputation and/or the rendering of our internal controls ineffective, all of which could adversely effect our business and financial condition.

Physical Acts of War, Terrorism or Other Attacks on any of Our Facilities or Other Infrastructure Could Have an Adverse Effect on Our Business, Results of Operations and Financial Condition

As a result of the continued threat of physical acts of war, terrorism, or other attacks in the United States, our electric generation, fuel storage, transmission and distribution facilities and other infrastructure, including nuclear and other power plants, transformer and high voltage lines and substations, or the facilities or other infrastructure of an interconnected company, could be direct targets of, or indirect casualties of, an act of war, terrorism, or other attack, which could result in disruption of our ability to generate, purchase, transmit or distribute electricity for a significant period of time, otherwise disrupt our customer operations and/or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such disruption or incident could result in a significant decrease in revenue, significant additional capital and operating costs, including costs to implement additional security systems or personnel to purchase electricity and to replace or repair our assets over and above any available insurance reimbursement, higher insurance deductibles, higher premiums and more restrictive insurance policies, greater regulation with higher attendant costs, generally, and significant damage to our reputation, which could have a material adverse effect on our business, results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters or Could be Canceled Which Could Adversely Affect Our Business and Results of Operations

Our business plan calls for execution of extensive capital investments in electric generation, transmission and distribution, including but not limited to our *Energizing the Future* transmission expansion program. We may be exposed to the risk of substantial price increases in, or the adequacy or availability of, the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors' inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates.

Changes in Technology and Regulatory Policies May Significantly Make Our Generating Facilities Less Competitive and Adversely Affect Our Results of Operations

We primarily generate electricity at large central station generation facilities. This method results in economies of scale and lower unit costs than newer generation technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in newer generation technologies will make them more cost-effective, or that changes in regulatory policy will create benefits that otherwise make these new technologies more competitive with central station electricity production. Increased competition, whether from such advances in technologies or from changes in regulatory policy, could result in permanent reductions in our historical load, adversely impact scheduling of generation, and decrease sales and revenues from our existing generation assets, which could have a material adverse effect on our results of operations.

Further, to the extent that new generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning and could adversely affect our business and results of operations.

Certain FirstEnergy Companies May Not be Able to Meet Their Obligations to or on behalf of Other FirstEnergy Companies or Their Affiliates

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies because of transactions involving energy, coal, other commodities, services and hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, resulting in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Our hedging activities are generally undertaken with a view to overall FirstEnergy exposures. Some FirstEnergy companies may therefore be more or less hedged than if they were to engage in such transactions alone. Certain FirstEnergy companies also provide guarantees to third party creditors on behalf of other FirstEnergy affiliate companies under transactions of the type described above or under financing transactions. Any failure to perform under such a guarantee by such FirstEnergy guarantor company or under the underlying transaction by the FirstEnergy company on whose behalf the guarantee was issued could have similar adverse impacts on one or both FirstEnergy companies or their affiliates.

Certain FirstEnergy Companies Have Guaranteed the Performance of Third Parties, Which May Result in Substantial Costs or the Incurrence of Additional Debt

Certain FirstEnergy companies have issued guarantees of the performance of others, which obligates such FirstEnergy companies to perform in the event that the third parties do not perform. For instance, FE is a guarantor under a syndicated senior secured term loan facility, under which Global Holding borrowed $300 million. In the event of non-performance by the third parties, FirstEnergy could incur substantial cost to fulfill this obligation and other obligations under such guarantees. Such performance guarantees could have a material adverse impact on our financial position and operating results.

Additionally, with respect to FEV's investment in Global Holding, due to distress in the coal market and industry, Global Holding could require additional capital from its owners, including FEV, to fund operations and meet its obligations under its term loan facility. These capital requirements could be significant and if other partners do not fund the additional capital, resulting in FEV increasing its equity ownership and obtaining the ability to direct the significant activities of Global Holding, FEV may be required to consolidate Global Holding, increasing FirstEnergy's long term debt by $300 million.

Energy Companies are Subject to Adverse Publicity Which Make Them Vulnerable to Negative Regulatory and Legislative Outcomes

Energy companies, including FirstEnergy's utility subsidiaries, have been the subject of criticism on matters including the reliability of their distribution services and the speed with which they are able to respond to power outages, such as those caused by storm damage. Adverse publicity of this nature, as well as negative publicity associated with the operation of nuclear and/or coal-fired facilities or proceedings seeking regulatory recoveries may cause less favorable legislative and regulatory outcomes and damage our reputation, which could have an adverse impact on our business.

Risks Associated With Regulation

To the Extent Our Policies to Control Costs Designed to Mitigate Low Energy, Capacity and Market Prices are Unsuccessful, We Could Experience a Negative Impact on Our Results of Operations and Financial Condition

Since 2012, as part of our ongoing comprehensive review of competitive operations related to, among other things, plant economics, we have deactivated more than 5,000 MW of competitive generation. To the extent our policies designed to control our costs, or other facets of our financial plan, are unsuccessful, we could experience a negative impact on our results of operations and financial condition. To address problems in the capacity market, PJM in December 2014 proposed significant market reforms, including its

Capacity Performance proposal. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and the August 2015 PJM RPM auction incorporated the Capacity Performance reforms. To the extent PJM's Capacity Performance market reforms do not work as intended, energy and capacity market prices may remain volatile and low.

Any Denial of, or Delay in, Cost Recovery Resulting from OE's, CEI's and TE's Pending ESP IV Before the PUCO May Impose Risks on Our Operations and May Negatively Impact Our Credit Ratings, Results of Operations and Financial Condition

ESPs may be filed in Ohio as a means to establish the mechanism by which generation rates are set and may also include other provisions related to distribution and transmission service, all of which is subject to the approval of the PUCO. As a result, OE, CEI, and TE may not be authorized to implement all of the rates, riders, and mechanisms for which they are seeking approval, or there may be a delay in such authorization. OE, CEI, and TE filed their proposed ESP IV entitled *Powering Ohio's Progress* that, including the impact of stipulations filed in the case, contemplates continuing a base distribution rate freeze and includes proposals to continue their Rider DCR mechanism and competitive bidding process for non-shopping load and to undertake and implement an Economic Stability Program provision, which includes an eight-year FERC-jurisdictional PPA with FES for the output of Sammis, Davis-Besse and FES' share of OVEC, designed to provide customers retail rate stability against market prices over a longer term.

OE, CEI, and TE expect to receive a decision on their ESP IV in March 2016. On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends vigorously to defend against such challenges. The failure to obtain approval of the ESP IV PPA or a successful challenge could negatively and materially impact the future results of operations and financial condition of FE and FES.

Complex and Changing Government Regulations, Including Those Associated With Rates and Rate Cases Could Have a Negative Impact on Our Results of Operations

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influence our operating environment. Changes in, or reinterpretations of, existing laws or regulations, or the imposition of new laws or regulations, could require us to incur additional costs or change the way we conduct our business, and therefore could have an adverse impact on our results of operations.

Our transmission and operating utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may be decreased as a result of actions taken by FERC or by one or more of the state regulatory commissions in which our utility subsidiaries operate. Also, these rates may not be set to recover such utility's expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. For example, we may be unable to timely recover the costs for our energy efficiency investments or expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner. Further, there can be no assurance that we will retain the expected recovery in future rate cases.

In addition, as a U.S. corporation, we are subject to U.S. laws, Executive Orders, and regulations administered and enforced by the U.S. Department of Treasury and the Department of Justice restricting or prohibiting business dealings in or with certain nations and with certain specially designated nationals (individuals and legal entities). If any of our existing or future operations or investments, including our joint venture investment in Signal Peak or our continued procurement of uranium from existing suppliers, are subsequently determined to involve such prohibited parties we could be in violation of certain covenants in our financing documents and unless we cease or modify such dealings, we could also be in violation of such U.S. laws, Executive Orders and sanctions regulations, each of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

State Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in, Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition

Each of the Utilities' retail rates are set by its respective regulatory agency for utilities in the state in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated deferred income taxes and income taxes payable across the FirstEnergy utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs (including for example accelerated deployment of smart meters); and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases. FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities, including the pending ESP IV in Ohio will be granted in whole or in part. Any denial of, or delay in, any base rate request could restrict the applicable Utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, and reduce liquidity and increase financing costs.

Federal Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition.

FERC policy currently permits recovery of prudently-incurred costs associated with wholesale power rates and the expansion and updating of transmission infrastructure within its jurisdiction. If FERC were to adopt a different policy regarding recovery of transmission costs or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be affected. If FERC were to lower the rate of return it has authorized for FirstEnergy's cost-based wholesale power rates or transmission investments and facilities, it could reduce future earnings and cash flows, and impact our financial condition.

Regulatory Changes in the Electric Industry Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of regulatory initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including the states in which we do business. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities and competitive energy providers conduct their business. FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry.

If any regulatory efforts result in decreased margins or unrecoverable costs, our business and results of operations would be adversely affected. We cannot predict the extent or timing of further regulatory efforts to modify our business or the industry.

The Business Operations of Our Subsidiaries That Sell Wholesale Power Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation

FERC granted certain FirstEnergy generating subsidiaries authority to sell electric energy, capacity and ancillary services at market-based rates. These orders also granted waivers of certain FERC accounting, record-keeping and reporting requirements, as well as, for certain of these subsidiaries, waivers of the requirements to obtain FERC approval for issuances of securities. FERC's orders that grant this market-based rate authority reserve with FERC the right to revoke or revise that authority if FERC subsequently determines that these companies can exercise market power in transmission or generation, or create barriers to entry, or have engaged in prohibited affiliate transactions. In the event that one or more of FirstEnergy's market-based rate authorizations were to be revoked or adversely revised, the affected FirstEnergy subsidiary(ies) may be subject to sanctions and penalties, and would be required to file with FERC for authorization of individual wholesale sales transactions, which could involve costly and possibly lengthy regulatory proceedings and the loss of flexibility afforded by the waivers associated with the current market-based rate authorizations.

There Are Uncertainties Relating to Our Participation in RTOs

RTO rules could affect our ability to sell energy and capacity produced by our generating facilities to users in certain markets. The rules governing the various regional power markets may change from time to time, which could affect our costs or revenues. In some cases these changes are contrary to our interests and adverse to our financial returns. The prices in day-ahead and real-time energy markets and RTO capacity markets have been volatile and RTO rules may contribute to this volatility.

All of our generating assets currently participate in PJM, which conducts RPM auctions for capacity on an annual planning year basis. The prices our generating companies can charge for their capacity are determined by the results of the PJM auctions, which are impacted by the supply and demand of capacity resources and load within PJM and also may be impacted by transmission system constraints and PJM rules relating to bidding for DR, energy efficiency resources, and imports, among others. Auction prices could fluctuate substantially over relatively short periods of time. To the extent PJM's Capacity Performance market reforms do not work as intended, energy and capacity market prices may remain volatile and low. We cannot predict the outcome of future auctions, but if the auction prices are sustained at low levels, our results of operations, financial condition and cash flows could be adversely impacted.

We incur fees and costs to participate in RTOs. Administrative costs imposed by RTOs, including the cost of administering energy markets, may increase. To the degree we incur significant additional fees and increased costs to participate in an RTO, and are limited with respect to recovery of such costs from retail customers, our results of operations and cash flows could be significantly impacted.

We may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. We may be required to expand our transmission system according to decisions made by an RTO rather than our own internal planning processes. Various proposals and proceedings before FERC may cause transmission rates to change from time to time. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on us.

As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO's market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.

Energy Efficiency and Peak Demand Reduction Mandates and Energy Price Increases Could Negatively Impact Our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption. Such conservation programs could result in load reduction and adversely impact our financial results in different ways. To the extent conservation results in reduced energy demand or significantly slows the growth in demand, the value of our competitive generation and other unregulated business activities could be adversely impacted. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery time frame in the states where we operate. Currently, only our Ohio Companies recover lost distribution revenues that result between distribution rate cases. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We have already been adversely impacted by reduced electric usage due in part to energy conservation efforts such as the use of efficient lighting products such as CFLs, halogens and LEDs. We could also be adversely impacted if any future energy price increases result in a decrease in customer usage. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Additionally failure to meet regulatory or legislative requirements to reduce energy consumption or otherwise increase energy efficiency could result in penalties that could adversely affect our results.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

Where federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation does not also provide for adequate cost recovery, it could result in significant changes in our business, including REC purchase costs, purchased power and capital expenditures. Such mandatory renewable portfolio requirements may have an adverse effect on our financial condition or results of operations.

The EPA is Conducting NSR Investigations at a Number of Generating Plants that We Currently or Formerly Owned, the Results of Which Could Negatively Impact Our Results of Operations and Financial Condition

We may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of EPA's NSR programs. Under the CAA, modification of our generation facilities in a manner that results in increased emissions could subject our existing generation facilities to the far more stringent new source standards applicable to new generation facilities.

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work considered by the companies to be routine maintenance. EPA has investigated alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position but we are unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with New Environmental Laws, Including Limitations on GHG Emissions, Could Adversely Affect Cash Flow and Profitability

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for, among other things, installation and operation of pollution control equipment, emissions monitoring and fees, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are unreasonable.

In December 2011, the EPA finalized MATS to establish emission standards for, among other things, mercury, PM and HCl, for electric generating units. The costs associated with MATS compliance, and other environmental laws, is substantial. As a result of a comprehensive review of FirstEnergy's coal-fired generating facilities in light of MATS and other expanded requirements, we deactivated twenty-six (26) older coal-fired generating units in 2012, 2013, and 2015.

Moreover, new environmental laws or regulations including, but not limited to EPA's CPP requiring reductions of GHG emissions and CWA effluent limitations imposing more stringent water discharge regulations, or changes to existing environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of certain of our generation facilities, we will not directly recover through rates additional costs incurred for such compliance. Our compliance strategy, including but not limited to, our assumptions regarding estimated compliance costs, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations or new interpretations of longstanding requirements, even if caused by factors beyond our control, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations.

At the international level, the Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. Further, due to the uncertainty of control technologies available to reduce GHG emissions, any other legal obligation that requires substantial reductions of GHG emissions could result in substantial additional costs, adversely affecting cash flow and profitability, and raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

We Could be Exposed to Private Rights of Action Relating to Environmental Matters Seeking Damages Under Various State and Federal Law Theories

Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other relief. For example, claims have been made against certain energy companies alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in other actions making similar allegations. An unfavorable ruling in any such case could result in the need to make modifications to our coal-fired plants or reduce emissions, suspend operations or pay money damages or penalties. Adverse rulings in these or other types of actions could have an adverse impact on our results of operations and financial condition and could significantly impact our operations.

Various Federal and State Water and Solid, Non-Hazardous and Hazardous Waste Regulations May Require Us to Make Material Capital Expenditures

In September 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water under the CWA. The EPA has also established performance standards under the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants, specifically, reducing impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) to a 12% annual average and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system) using site-specific controls based on studies to be submitted to permitting authorities. FirstEnergy is studying the cost and effectiveness of various control options to divert fish away from its plants' cooling water intake systems. Depending on the results of such studies and implementation of impingement and entrainment performance standards by permitting authorities, the future costs of compliance with these standards may require material capital expenditures.

We Are or May be Subject to Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities

We may be subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. We are currently involved in a number of proceedings relating to sites where hazardous substances have been released and we may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Remediation activities associated with our former MGP operations are one source of such costs. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material.

In some cases, a third party who has acquired assets from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities

We have been named as a defendant in pending asbestos litigation involving multiple plaintiffs and multiple defendants. In addition, asbestos and other regulated substances are, and may continue to be, present at our facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us.

The Continuing Availability and Operation of Generating Units is Dependent on Retaining or Renewing the Necessary Licenses, Permits, and Operating Authority from Governmental Entities, Including the NRC

We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of any of these agencies and we are not assured that any such permits, approvals or certifications will be renewed.

Potential NRC Regulation in Response to the Incident at Japan's Fukushima Daiichi Nuclear Plant Could Adversely Affect Our Business and Financial Condition

As a result of the NRC's investigation of the incident at the Fukushima Daiichi nuclear plant, the NRC has begun to promulgate new or revised requirements with respect to nuclear plants located in the United States, which could necessitate additional expenditures at our nuclear plants. For example, as a follow up to the NRC near-term Task Force's review and analysis of the Fukushima Daiichi accident, in January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the task force. The NRC has also issued orders and guidance that increases procedural and testing requirements, requires physical modifications to our plants and is expected to increase future compliance and operating costs. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. It is also possible that the NRC could suspend or otherwise delay nuclear relicensing proceedings. The impact of any such regulatory actions could adversely affect FirstEnergy's financial condition or results of operations.

The Risks Associated with Climate Change May Impact Our Results of Operations and Cash Flows

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Climate change could also affect the availability of a secure and economical supply of water in some locations, which is essential for continued operation of generating plants. Further, as extreme weather conditions increase system stress, we may incur costs relating to additional system backup or service interruptions, and in some instances we may be unable to recover such costs. For all of these reasons, these physical risks could have an adverse financial impact on our operations and operating results. Climate change poses other financial risks as well. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional system assets and purchase additional power. Additionally, decreased energy use due to weather changes may affect our financial condition through decreased rates, revenues, margins or earnings.

Future Changes in Accounting Standards May Affect Our Reported Financial Results

The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position.

Changes in Local, State or Federal Tax Laws Applicable To Us or Adverse Audit Results or Tax Rulings, and Any Resulting Increases in Taxes and Fees, May Adversely Affect Our Results of Operations, Financial Condition and Cash Flows

FirstEnergy is subject to various local, state and federal taxes, including income, franchise, real estate, sales and use and employment-related taxes. We exercise significant judgment in calculating such tax obligations, booking reserves as necessary to reflect potential adverse outcomes regarding tax positions we have taken and utilizing tax benefits, such as carryforwards and credits. Additionally, various tax rate and fee increases may be proposed or considered in connection with such changes in local, state or federal tax law. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by legislatures or regulatory bodies. Any such changes, or any adverse tax audit results or adverse tax rulings on positions taken by FirstEnergy or its subsidiaries could have a negative impact on its results of operations, financial condition and cash flows.

Risks Associated With Financing and Capital Structure

Volatility or Unfavorable Conditions in the Capital and Credit Markets May Adversely Affect Our Business, Including the Immediate Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments, Our Ability to Hedge Effectively Our Generation Portfolio, and the Competitiveness and Liquidity of Energy Markets; Each Could Adversely Affect Our Results of Operations, Cash Flows and Financial Condition

We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. We also deposit cash in short-term investments. Volatility in the capital and credit markets could adversely affect our ability to draw on our credit facilities and cash. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.

Fluctuations in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant foreign or domestic financial institutions or foreign governments could adversely affect our access to liquidity needed for our business. Unfavorable conditions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash.

Energy markets depend heavily on active participation by multiple counterparties, which could be adversely affected by disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows.

Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our or Our Subsidiaries' Financing Costs, Ability to Access Capital and Requirement to Post Collateral and the Ability to Continue Successfully Implementing Our Retail Sales Strategy

We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Past disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for certain of our variable interest rate debt securities and failed remarketings of variable interest rate tax-exempt debt issued to finance certain of our facilities. Similar future disruptions could increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that are beyond our risk management processes. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs that our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our or our subsidiaries' credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. A downgrade in our credit rating, or that of our subsidiaries, could also preclude certain retail customers from executing supply contracts with us and therefore impact our ability to successfully implement our retail sales strategy. Furthermore, a downgrade could increase the cost of such capital by causing us to incur higher interest rates and fees associated with such capital. A rating downgrade would increase our interest expense on certain of FirstEnergy's long-term debt obligations and would also increase the fees we pay on our various existing credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital.

The Stability of Counterparties Could Adversely Affect Us

We are exposed to the risk that counterparties that owe us money, power, fuel or other commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Some of our agreements contain provisions that require the counterparties to provide credit support to secure all or part of their obligations to FirstEnergy or its subsidiaries. If the counterparties to these arrangements fail to perform, we may have a right to receive the proceeds from the credit support provided, however the credit support may not always be adequate to cover the related obligations. In such event, we may incur losses in addition to amounts, if any, already paid to the counterparties, including by being forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by customers or other counterparties may be greater than the estimates predict, which could have a material adverse effect on our results of operations and financial condition.

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on Our Utility Subsidiaries' Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Financial Condition

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow, including our ability to pay dividends and service debt, is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Our utility and transmission subsidiaries are regulated by various state utility and federal commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state and federal commissions could attempt to impose restrictions on the ability of our utility and transmission subsidiaries to pay dividends or otherwise restrict cash payments to us.

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts They May be Paid

Our Board of Directors will continue to regularly evaluate our common stock dividend and determine an appropriate dividend each quarter taking into account such factors as, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Met-Ed Exhibit JD-15
Attachment A
Witness: J. Dipre

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The first mortgage indentures for the Ohio Companies, Penn, MP, PE, WP, FG and NG constitute direct first liens on substantially all of the respective physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See Note 6, Leases, and Note 11, Capitalization, of the Combined Notes to Consolidated Financial Statements for information concerning leases and financing encumbrances affecting certain of the Utilities', FG's and NG's properties.

FirstEnergy controls the following generation sources as of February 16, 2016, shown in the table below. Except for the leasehold interests, OVEC participation and wind and solar power arrangements referenced in the footnotes to the table, substantially all of FES' competitive generating units are owned by NG (nuclear) and FG (non-nuclear); the regulated generating units are owned by JCP&L and MP.

Plant (Location)	Unit	Total	Competitive: FES	Competitive: AE Supply	Regulated
			Net Demonstrated Capacity (MW)		
Super-critical Coal-fired:					
Bruce Mansfield (Shippingport, PA)	1	830 (1)	830	—	—
Bruce Mansfield (Shippingport, PA)	2	830	830	—	—
Bruce Mansfield (Shippingport, PA)	3	830	830	—	—
Harrison (Haywood, WV)	1-3	1,984	—	—	1,984
Pleasants (Willow Island, WV)	1-2	1,300	—	1,300	—
W. H. Sammis (Stratton, OH)	6-7	1,200	1,200	—	—
Fort Martin (Maidsville, WV)	1-2	1,098	—	—	1,098
		8,072	3,690	1,300	3,082
Sub-critical and Other Coal-fired:					
W. H. Sammis (Stratton, OH)	1-5	1,010	1,010	—	—
Bay Shore (Toledo, OH)	1	136	136	—	—
OVEC (Cheshire, OH) (Madison, IN)	1-11	188 (2)	110	67	11
		1,334	1,256	67	11
Nuclear:					
Beaver Valley (Shippingport, PA)	1	939	939	—	—
Beaver Valley (Shippingport, PA)	2	933 (3)	933	—	—
Davis-Besse (Oak Harbor, OH)	1	908	908	—	—
Perry (N. Perry Village, OH)	1	1,268 (4)	1,268	—	—
		4,048	4,048	—	—
Gas/Oil-fired:					
AE Nos. 1, 2, 3, 4 & 5 (Springdale, PA)	1-5	638	—	638	—
West Lorain (Lorain, OH)	1-6	545	545	—	—
AE Nos. 12 & 13 (Chambersburg, PA)	12-13	88	—	88	—
AE Nos. 8 & 9 (Gans, PA)	8-9	88	—	88	—
Forked River (Ocean County, NJ)	2	86	86	—	—
Hunlock CT (Hunlock Creek, PA)	1	45	—	45	—
Buchanan (Oakwood, VA)	1-2	43 (5)	—	43	—
Other		59	59	—	—
		1,592	690	902	—
Pumped-storage Hydro:					
Bath County (Warm Springs, VA)	1-6	1,200 (6)	—	713	487
Yard's Creek (Blairstown Twp., NJ)	1-3	210 (7)	—	—	210
		1,410	—	713	697
Wind and Solar Power		496 (8)	496	—	—
Total		16,952	10,180	2,982	3,790

(1) Includes FE's leasehold interest of 93.83% (779 MW) from non-affiliates.
(2) Represents FG's 4.85%, AE Supply's 3.01% and MP's 0.49% entitlement based on their participation in OVEC.
(3) Includes OE's leasehold interest of 2.60% (24 MW) from non-affiliates of which FES purchases all the output pursuant to full output cost-of-service PSAs.
(4) Includes OE's leasehold interest of 3.75% (48 MW) from non-affiliates of which FES purchases all the output pursuant to full output cost-of-service PSAs.
(5) Represents Buchanan Energy's 50% interest. Buchanan Energy is a subsidiary of AE Supply. CNX Gas Corporation and Buchanan Energy have equal ownership interests in Buchanan Generation, LLC. AE Supply operates and dispatches 100% of Buchanan Generation, LLC's 86 MWs.
(6) Represents AGC's 40% interest in Bath County, a pumped-storage hydroelectric station. The station is operated by 60% owner Virginia Electric and Power Company. AGC is 59% owned by AE Supply and 41% owned by MP.
(7) Represents JCP&L's 50% ownership interest.
(8) Includes 167 MW from leased facilities and 329 MW under power purchase agreements.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. FirstEnergy's overhead and underground transmission lines aggregate 24,211 pole miles.

The Utilities' electric distribution systems include 268,682 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of approximately 154,612,802 kV-amperes.

All of FirstEnergy's generation, transmission and distribution assets operate in PJM.

FirstEnergy's distribution and transmission systems as of December 31, 2015, consist of the following:

	Distribution Lines(1)	Transmission Lines(1)	Substation Transformer Capacity(2)
			kV Amperes
OE	61,181	377	7,651,995
Penn	13,537	—	1,090,120
CEI	33,368	—	10,388,929
TE	18,999	73	3,025,373
JCP&L	23,277	2,573	22,367,086
ME	18,859	1,497	11,230,635
PN	27,459	2,755	16,694,883
ATSI(3)	—	7,773	32,328,674
WP	24,365	4,290	18,489,266
MP	22,062	2,559	15,098,632
PE	25,575	2,098	15,672,209
TrAIL	—	216	575,000
Total	268,682	24,211	154,612,802

(1) Circuit Miles
(2) Top rating of in-service power transformers only. Excludes grounding banks, station power transformers, and generator and customer-owned transformers.
(3) Represents transmission line assets of 69 kV and greater located in the service territories of OE, Penn, CEI and TE.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 14, Regulatory Matters, and Note 15, Commitments, Guarantees and Contingencies of the Combined Notes to Consolidated Financial Statements for a description of certain legal proceedings involving FirstEnergy and FES.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

The information required by Item 5 regarding FirstEnergy's market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included in Item 6.

Information for FES is not disclosed because it is a wholly owned subsidiary of FirstEnergy and there is no market for its common stock.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy's 2016 proxy statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act.

FirstEnergy had no transactions regarding purchases of FE common stock during the fourth quarter of 2015.

FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Revenues	$ 15,026	$ 15,049	$ 14,892	$ 15,255	$ 16,087
Income From Continuing Operations	$ 578	$ 213	$ 375	$ 755	$ 856
Earnings Available to FirstEnergy Corp.	$ 578	$ 299	$ 392	$ 770	$ 885
Earnings per Share of Common Stock:					
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.81	$ 2.19
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Basic - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.85	$ 2.22
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.80	$ 2.18
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Diluted - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.84	$ 2.21
Weighted Average Shares Outstanding:					
Basic	422	420	418	418	399
Diluted	424	421	419	419	401
Dividends Declared per Share of Common Stock	$ 1.44	$ 1.44	$ 1.65	$ 2.20	$ 2.20
Total Assets(1)	$ 52,187	$ 51,648	$ 50,058	$ 50,175	$ 47,410
Capitalization as of December 31:					
Total Equity	$ 12,422	$ 12,422	$ 12,695	$ 13,093	$ 13,299
Long-Term Debt and Other Long-Term Obligations	19,192	19,176	15,831	15,179	15,716
Total Capitalization	$ 31,614	$ 31,598	$ 28,526	$ 28,272	$ 29,015

(1)Reflects the application of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires all accumulated deferred income taxes to be classified as non-current. The retrospective change decreased Total Assets as of December 31 as follows: 2014 - $518 million, 2013 -$366 million, 2012 - $319 million as these amounts were reclassified from current assets to non-current liabilities.

PRICE RANGE OF COMMON STOCK

The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

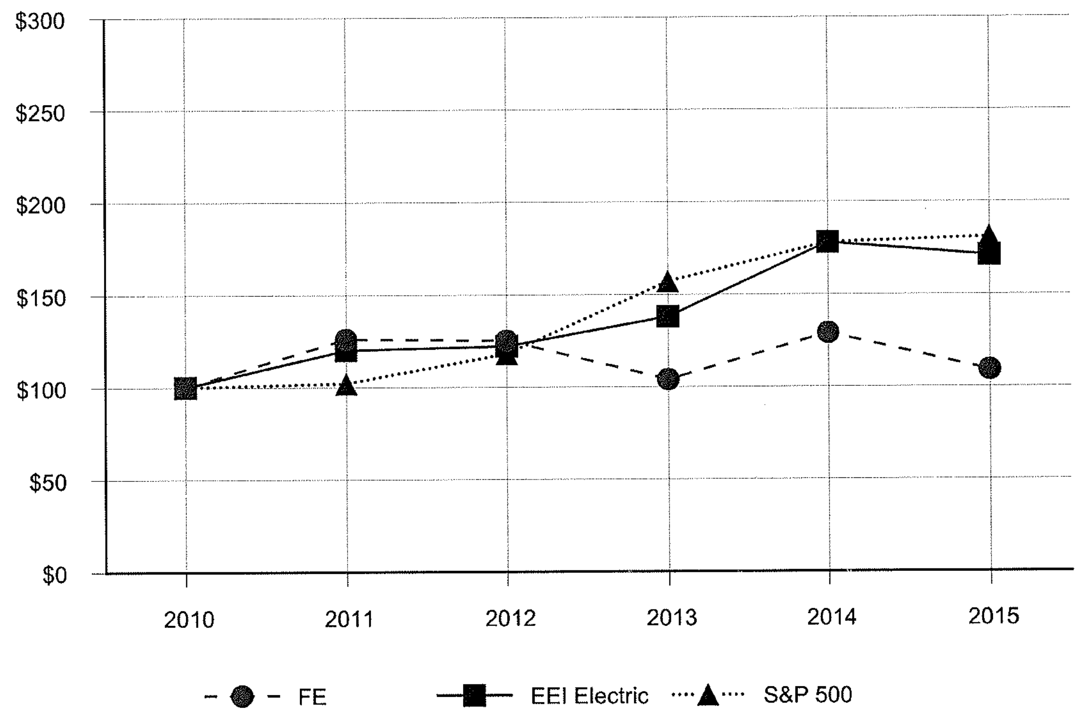
	2015		2014	
	High	Low	High	Low
First Quarter	$ 41.68	$ 33.82	$ 34.28	$ 30.10
Second Quarter	$ 37.05	$ 32.46	$ 35.59	$ 31.17
Third Quarter	$ 35.09	$ 30.31	$ 34.95	$ 29.98
Fourth Quarter	$ 33.00	$ 28.89	$ 40.84	$ 33.04
Yearly	$ 41.68	$ 28.89	$ 40.84	$ 29.98

Closing prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2010 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.

Total Return Cumulative Values
($100 Investment on December 31, 2010)



HOLDERS OF COMMON STOCK

There were 90,633 and 90,346 holders of 423,560,397 and 423,650,645 shares of FirstEnergy's common stock as of December 31, 2015 and January 31, 2016, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11, Capitalization of the Combined Notes to Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "forecast," "target," "will," "intend," "believe," "project," "estimate," "plan" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including but not limited to, the proposed transmission asset transfer to MAIT, and the effectiveness of our strategy to reflect a more regulated business profile.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and the ESP IV in Ohio.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; and FERC's compliance and enforcement activity, including compliance and enforcement activity related to NERC's mandatory reliability standards.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil prices, and their availability and impact on margins and asset valuations.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, the effects of the EPA's CPP, CCR, CSAPR and MATS programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation, or potential regulatory initiatives or rulemakings (including that such initiatives or rulemakings could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments and as it relates to the reliability of the transmission grid, the timing thereof.
- The impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building at Davis-Besse.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our cash flow improvement plan and other proposed capital raising initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.

- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

These forward looking statements are also qualified by, and should be read together with, the risk factors included in (a) Item 1A. Risk Factors, (b) this Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by the registrants. The foregoing review of factors also should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

FIRSTENERGY CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRSTENERGY'S BUSINESS

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission, and CES.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

The service areas of, and customers served by, FirstEnergy's regulated distribution utilities are summarized below (in thousands):

Company	Area Served	Customers Served [1]
OE	Central and Northeastern Ohio	1,038
Penn	Western Pennsylvania	164
CEI	Northeastern Ohio	746
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,109
ME	Eastern Pennsylvania	561
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	723
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	401
		6,028

[1] As of December 31, 2015

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity. The CES segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment's customers.

The CES segment expects to sell its annual generation output of approximately 75 to 80 million MWHs, with up to an additional 5 million MWHs available from PPAs for wind, solar and its entitlement from OVEC, through a target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct), 10 to 20 million MWHs in block wholesale sales, including Structured Sales, and 10 to 20 million MWHs of spot wholesale sales.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy continues to capitalize on investment opportunities available in its Regulated Transmission and Regulated Distribution businesses while implementing a conservative hedging strategy at its Competitive business. FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy over time.

FirstEnergy's regulated investment strategy focuses on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years.

Regulated Transmission

The centerpiece of FirstEnergy's regulated investment strategy is the *Energizing the Future* transmission expansion plan. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize FirstEnergy's transmission system.

In conjunction with its transmission expansion plan, in 2015 ATSI received FERC-approval of its "forward looking" rate, implemented on January 1, 2015, where transmission rates are based on estimated costs for the current year with an annual true up, and an ROE of: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and 10.38% effective January 1, 2016, unless changed pursuant to Section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Additionally, in June 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. If approved, MAIT will operate similar to FET's two existing stand-alone transmission subsidiaries ATSI and TrAIL. FERC approval is expected in March 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

Regulated Distribution

During 2015, FirstEnergy continued to pursue key regulatory initiatives across its utility footprint, focusing on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives included:

- The Ohio Companies' ESP IV, *Powering Ohio's Progress:* The ESP IV, including the impact of filed stipulations in the case, contemplates continuing a distribution rate freeze through May 2024 while helping ensure continued availability of more than 3,200 MWs of FirstEnergy's critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers. Evidentiary hearings commenced in August 2015. On December 1, 2015, FirstEnergy's Ohio Companies filed an additional settlement at the PUCO, which included the PUCO Staff as a signatory party, that sets forth ambitious steps to help safeguard customers against retail generation price increases in future years, deploy new energy efficiency programs, and provide a clear path to a cleaner energy future by establishing a goal to substantially reduce carbon emissions. The settlement includes an eight-year rate provision (Rider RRS) designed to help protect customers against rising retail price increases and market volatility, while helping preserve vital baseload power plants that serve Ohio customers and provide thousands of family-sustaining jobs in the state. The plants involved include the Davis-Besse Nuclear Power Station, the W.H. Sammis Plant, and a portion of the output of OVEC units in Gallipolis, Ohio, and Madison, Indiana. A decision is anticipated in March 2016. On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge, in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

- Implementation of New Rates in Pennsylvania for ME, PN, Penn and WP: The new rates were approved in April 2015 and went into effect in May 2015, providing for an increase in annual revenues of approximately $293 million and approximately $88 million of additional annual operating expenses. Furthermore, in October 2015, the Pennsylvania companies filed LTIIPs with the PPUC for infrastructure improvements over the 2016 to 2020 period totaling nearly $245 million, which were approved on February 11, 2016. The Pennsylvania Companies filed DSIC riders on February 16, 2016, for quarterly cost recovery associated with the projects approved in the LTIIPs.

- Implementation of New Rates in West Virginia for MP and PE: The new rates were approved and went into effect in February 2015, resulting in recovery of $63 million annually for reliability investments and expenses, storm damage expenses, and investments in operating improvements and environmental compliance at MP's and PE's regulated coal-fired power plants in West Virginia. MP and PE also received orders in December 2015 in their ENEC case and their biennial vegetation management program surcharge reconciliation, resulting in revenue increases, effective January 1, 2016, totaling $96.9 million and $36.7 million, respectively, to recover deferred costs.

Additionally, during 2015, the NJBPU issued orders on JCP&L's base rate proceedings and its generic storm proceedings resulting in a reduction of approximately $34 million in annual revenues, inclusive of recovery of 2011 and 2012 storm costs, as well as the NJBPU's recently modified CTA policy. As part of the base rate order, JCP&L is required to file another base rate case no later than April 1, 2017.

Competitive Energy Services

FirstEnergy continues its strategy for its competitive business to more effectively hedge its generation by reducing exposure to weather-sensitive load in certain sales channels and pursuing high-margin sales, while leaving a portion of its generation available to capture future market opportunities or to mitigate risk. This strategy is designed to position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. On average, the CES segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs available from purchased power agreements for wind, solar and its entitlement from OVEC. In 2015, CES sold approximately 75 million MWHs of which 68 million MWHs were through contract sales with another 7 million MWHs of wholesale sales. As of December 31, 2015, committed sales for 2016 and 2017 were approximately 61 million MWHs and 38 million MWHs, respectively.

From a generation perspective, FirstEnergy continues to focus on ensuring its competitive fleet is cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. FirstEnergy's total cost for MATS compliance is expected to be approximately $345 million ($168 million at CES and $177 million at Regulated Distribution), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

During 2015, FirstEnergy completed scheduled shutdowns for three of its nuclear units - Beaver Valley Unit 1 and Unit 2 and the Perry Nuclear Power plant - for refueling and maintenance. During the outages, fuel assemblies were exchanged and numerous inspections and preventative maintenance and improvement projects were completed to ensure continued safe and reliable operations. Additionally, in December 2015, the NRC approved a 20-year license extension for the Davis-Besse Nuclear Power Station allowing the unit to operate until 2037.

Also, in 2015, PJM conducted the 2015 BRA for the 2018/2019 delivery year and Capacity Performance transition auctions for the 2016/2017 and 2017/2018 delivery years. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				**2017 - 2018**				**2018 - 2019***			
	Legacy Obligation		**Capacity Performance**		**Legacy Obligation**		**Capacity Performance**		**Base Generation**		**Capacity Performance**	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

Projected CES Capacity Revenue* ($ Millions)

	2016	**2017**	**2018**	**2019 (through 5/31)**
Capacity Revenue	$815	$590	$620	$260

*Includes revenues from the results of incremental/transitional capacity auctions, bilateral transactions and capacity transfer rights.

STRATEGY AND OUTLOOK

FirstEnergy owns a large and diverse mix of assets managed in an integrated model, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a competitive operations segment that owns or controls over 13,000 MWs of generation with a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy continues to focus on developing its transmission business, strengthening its regulated utilities, and managing overall risk and conservatively operating its competitive business.

FirstEnergy continues to focus on investment opportunities in its Regulated Transmission and Regulated Distribution segments. This investment strategy is focused on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. FirstEnergy expects to fund these investments through a combination of cash from operations, debt, and, depending on the regulated operating company, capital contributions from its parent. In the future, FirstEnergy may consider additional equity to fund capital requirements in its regulated operations.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses.

FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy Corp. over time. As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Regulated Transmission

As noted above, the centerpiece of FirstEnergy's growth strategy is a $4.2 billion investment in the *Energizing the Future* program from 2014 through 2017. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. This program is focused on a large number of small projects within the company's 24,000 mile service territory that improve service to customers. The projects within the program are either regulatory required or support reliability enhancement. Regulatory required projects include those requested by PJM to support grid reliability, generator deactivations, or shale gas expansion activities. The second category of projects, those that support reliability enhancement, focus on replacing aging equipment; increasing automation, communication, and security within the system; and increasing load serving capability. In the initial years of the program, the majority of the projects are located within the ATSI system, with expectations to move east across FirstEnergy's service territory over time. An additional $15 billion in transmission investment opportunities have been identified across the system beyond the 2014-2017 period, making this a continuing and sustainable platform for investment.

In 2016, FirstEnergy expects to receive approval to transfer transmission assets of JCP&L, Met-Ed and Penelec to MAIT, a new stand-alone transmission subsidiary.

Regulated Distribution

The five-state service territory served by FirstEnergy's Regulated Distribution segment also offers substantial opportunities for future investments to improve service to more than 6 million customers. In 2015, FirstEnergy completed major rate cases in West Virginia, Pennsylvania and New Jersey. In Pennsylvania, a filing for an infrastructure improvement plan that includes an investment of $245 million through 2020 was approved by the PPUC on February 11, 2016, and in Ohio, a comprehensive settlement in the ESP IV is pending PUCO approval. The ESP IV settlement contains additional opportunities for investment in the Ohio Companies, including grid modernization and energy efficiency as well as continuation of Rider DCR with revenue caps increasing $180 million over the term of the ESP IV. The settlement also includes a FERC-jurisdictional PPA where the Ohio Companies would purchase the output from FES' Davis-Besse nuclear plant, Sammis coal plant and entitlement to OVEC generation output, a total of 3,244 MW, for an eight-year term beginning June 1, 2016.

FirstEnergy also continues to closely monitor sales trends across its utility footprint. Within its Regulated Distribution segment, FirstEnergy continues to be impacted by lower customer usage as a result of energy efficiency mandates and products. During 2015, electric distribution deliveries on a weather-adjusted basis declined 1.6% in the residential customer class and 0.6% in the commercial customer class as compared to 2014. Furthermore, in the industrial sector, increases in the shale gas sector were more than offset with lower usage in the steel and mining sectors, resulting in an overall decrease in the industrial sector of 2.0%.

CES

FirstEnergy continues to focus on maintaining the value of its competitive business and continues to advocate for reforms that ensure the competitive wholesale markets adequately value baseload generation, which is essential for maintaining grid reliability. While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last several years to reposition this business for such a recovery. CES uses a conservative hedging strategy, and expects to sell its annual generation resources of approximately 75-80 million MWHs through a combination of retail and wholesale sales, maintaining 10-20 million MWHs to mitigate risk in the event of unplanned outages or extreme weather or to take advantage of market upside opportunities through the wholesale spot market.

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Years Ended December 31, 2015	2014	2013	Increase (Decrease) 2015 vs 2014		2014 vs 2013	
REVENUES:	$ 15,026	$ 15,049	$ 14,892	$ (23)	— %	$ 157	1 %
OPERATING EXPENSES:							
Fuel	1,855	2,280	2,496	(425)	(19)%	(216)	(9)%
Purchased power	4,318	4,716	3,963	(398)	(8)%	753	19 %
Other operating expenses	3,749	3,962	3,593	(213)	(5)%	369	10 %
Pension and OPEB mark-to-market adjustment	242	835	(256)	(593)	(71)%	1,091	(426)%
Provision for depreciation	1,282	1,220	1,202	62	5 %	18	1 %
Amortization of regulatory assets, net	268	12	539	256	2,133 %	(527)	(98)%
General taxes	978	962	978	16	2 %	(16)	(2)%
Impairment of long-lived assets	42	—	795	42	— %	(795)	(100)%
Total operating expenses	12,734	13,987	13,310	(1,253)	(9)%	677	5 %
OPERATING INCOME	2,292	1,062	1,582	1,230	116 %	(520)	(33)%
OTHER INCOME (EXPENSE):							
Loss on debt redemptions	—	(8)	(132)	8	(100)%	124	(94)%
Investment income (loss)	(22)	72	33	(94)	(131)%	39	118 %
Impairment of equity method investment	(362)	—	—	(362)	— %	—	— %
Interest expense	(1,132)	(1,073)	(1,016)	(59)	5 %	(57)	6 %
Capitalized financing costs	117	118	103	(1)	(1)%	15	15 %
Total other expense	(1,399)	(891)	(1,012)	(508)	57 %	121	(12)%
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570	722	422 %	(399)	(70)%
INCOME TAXES (BENEFITS)	315	(42)	195	357	(850)%	(237)	(122)%
INCOME FROM CONTINUING OPERATIONS	578	213	375	365	171 %	(162)	(43)%
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17	(86)	(100)%	69	406 %
NET INCOME	$ 578	$ 299	$ 392	$ 279	93 %	$ (93)	(24)%
EARNINGS PER SHARE OF COMMON STOCK:							
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%

FirstEnergy's net income in 2015 was $578 million, or basic and diluted earnings of $1.37 per share of common stock, compared with $299 million, or basic and diluted earnings of $0.71 per share of common stock in 2014, and $392 million, or basic and diluted earnings of $0.94 per share of common stock in 2013. Highlights of the key changes in year-over-year financial results are included below:

2015 compared with 2014

As further discussed below, FirstEnergy's 2015 income from continuing operations increased $365 million as compared to 2014, resulting from a year-over-year improvement of $506 million at CES, $153 million at Regulated Distribution and $75 million at Regulated Transmission, partially offset by a $369 million decrease at Corporate/Other.

In 2015, FirstEnergy's revenues decreased $23 million as compared to 2014, primarily resulting from a $905 million decrease at CES partially offset by a $523 million increase at Regulated Distribution and a $242 million increase at Regulated Transmission.

- The decrease in revenue at CES resulted from a 31 million MWHs decline in contract sales, in line with CES' strategy discussed above, partially offset by higher wholesale sales, including increased capacity revenue associated with higher capacity auction prices.
- The increase in revenue at Regulated Distribution resulted from the implementation of new rates at certain operating companies as well as a year-over-year increase in retail generation revenue, resulting from a lower number of customers shopping with an alternative generation supplier and higher retail transmission revenue, which is recovering higher transmission related expenses. Distribution deliveries decreased 0.8%, or 1.1 million MWHs, as weather adjusted sales declined as a result of energy efficiency mandates and products and decreases in certain industrial sectors, partially offset by an increase in weather-related sales.

- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses as well as ATSI's transition to a forward-looking rate, effective January 1, 2015. These increases were partially offset by a lower ROE at ATSI in the last six months of 2015 as part of the FERC-approved settlement discussed above.

Operating expenses decreased $1,253 million in 2015 as compared to 2014, including a $593 million decrease in the Company's pension and OPEB mark-to-market adjustment, reflecting a decrease at CES of $1,747 million, partially offset by increases at Regulated Distribution and Regulated Transmission of $255 million and $73 million, respectively.

Changes in certain operating expenses include the following:

- Fuel expense declined $425 million, primarily at CES, resulting from lower fossil generation associated with low energy prices, lower unit costs, and lower settlement and termination charges on fuel and transportation contracts.
- Purchased power decreased $398 million, primarily reflecting lower volumes at CES, resulting from lower contract sales, partially offset by higher volumes at Regulated Distribution due to lower customer shopping as discussed above, and higher capacity expense associated with higher capacity rates.
- Other operating expenses decreased $213 million, primarily reflecting a decrease at CES associated with lower PJM transmission, mark-to-market and retail-related costs partially offset by higher nuclear planned outage costs, partially offset by an increase at Regulated Distribution, resulting from higher network transmission expenses, which are recovered through transmission rates as discussed above, and higher operating and maintenance expenses associated with reliability improvements.
- Amortization of regulatory assets, net increased $256 million primarily reflecting the recovery of deferred costs, including storm costs, associated with the implementation of new rates discussed above.

FirstEnergy's other expenses increased $508 million, or 57%, year-over-year, primarily resulting from a $362 million pre-tax, non-cash impairment charge associated with FEV's investment in Global Holding, lower investment income, including a $65 million increase in OTTI, and higher interest expense associated with higher average debt levels.

FirstEnergy's effective tax rate on income from continuing operations was 35.3% in 2015 compared to (24.6)% in 2014. The increase in the effective tax rate was attributable to tax planning initiatives executed during 2014, including tax benefits associated with a change in accounting method with the IRS for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain state tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

<u>2014 compared with 2013</u>

FirstEnergy's 2014 income from continuing operations decreased $162 million as compared to 2013 resulting from a year-over-year decline of $182 million at CES and $36 million at Regulated Distribution, partially offset by a year-over-year improvement at Regulated Transmission of $9 million and $47 million at Corporate/Other.

In 2014, FirstEnergy's revenue increased $157 million compared to 2013. The increase resulted from a $382 million increase at Regulated Distribution and a $38 million increase at Regulated Transmission, partially offset by a decrease in CES revenues of $209 million.

- The increase in revenue at Regulated Distribution resulted from higher wholesale generation sales associated with the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of generation from AE Supply.
- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses.
- The decrease at CES resulted from lower contract sales as in 2014, CES began to reduce its exposure to weather sensitive load to more effectively hedge its generation, targeting annual contract sales of 65 to 75 million MWHs as compared to the 109 million MWHs sold in 2013. This change in strategy resulted in a 9% decrease in MWH sales in 2014 as compared to 2013.

Operating expenses increased $677 million in 2014 compared to 2013, including a $1,091 million increase in FirstEnergy's Pension and OPEB mark-to-market adjustment, primarily reflecting an increase at Regulated Distribution of $428 million, CES of $265 million and Regulated Transmission of $40 million.

Changes in certain operating expenses include the following:

- Lower fuel expense of $216 million, primarily reflected the deactivation of power plants in 2013 and increased outages. Fuel expense at CES and Regulated Distribution was further impacted by the October 2013 Harrison/Pleasants asset transfer.
- Purchased power increased $753 million, primarily reflecting higher CES purchases resulting from plant deactivations, increased outages and the asset transfer discussed above as well as higher unit pricing and capacity expense. The increase in unit pricing primarily resulted from market conditions associated with the extreme weather events in the first quarter of 2014, which included the polar vortex.

- Other operating expenses increased $369 million primarily resulting from higher costs at Regulated Distribution associated with network transmission expenses, increased vegetation management expenses in West Virginia, as well as higher operating and maintenance associated with reliability improvements, storm restoration costs and the Harrison/Pleasants asset transfer. CES' increase in other operating expenses was primarily attributable to higher transmission costs, which resulted from the market conditions associated with the extreme weather events in the first quarter of 2014, and higher mark-to-market expenses on derivative contracts, partially offset by lower generation operating and maintenance costs primarily resulting from the deactivation of generating plants and the Harrison/Pleasants asset transfer.

FirstEnergy's other expenses decreased $121 million year-over-year, primarily resulting from the absence of a loss on debt redemptions of $124 million recognized in 2013. Higher interest expense was offset by higher investment income and capitalized financing costs, primarily attributable to Regulated Transmission's *Energizing the Future* investment plan.

FirstEnergy's effective tax rate on income from continuing operations was (24.6)% compared to 34.2% in 2013. The decrease in the effective tax rate was attributable to tax benefits recognized in 2014 associated with an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

Net income by business segment was as follows:

				Increase (Decrease)	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 618	$ 465	$ 501	$ 153	$ (36)
Regulated Transmission	298	223	214	75	9
Competitive Energy Services	89	(331)	(218)	420	(113)
Corporate/Other [1]	(427)	(58)	(105)	(369)	47
Net Income	$ 578	$ 299	$ 392	$ 279	$ (93)
Basic Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)
Diluted Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)

[1] Consists primarily of interest on stand-alone holding company debt, none-core business related activity and corporate income taxes.

Summary of Results of Operations — 2015 Compared with 2014

Financial results for FirstEnergy's business segments in 2015 and 2014 were as follows:

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,429	$ 1,011	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,625	1,011	5,384	(994)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,548	—	1,456	(686)	4,318
Other operating expenses	2,242	154	1,670	(317)	3,749
Pension and OPEB mark-to-market	179	3	60	—	242
Provision for depreciation	672	156	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	8,146	422	5,076	(910)	12,734
Operating Income	1,479	589	308	(84)	2,292
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(586)	(161)	(192)	(193)	(1,132)
Capitalized financing costs	25	44	39	9	117
Total Other Expense	(519)	(117)	(169)	(594)	(1,399)
Income From Continuing Operations Before Income Taxes	960	472	139	(678)	893
Income taxes	342	174	50	(251)	315
Income From Continuing Operations	618	298	89	(427)	578
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$ 618	$ 298	$ 89	$ (427)	$ 578

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (Loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Impairment of equity method investment	—	—	—	—	—
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized financing costs	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

Changes Between 2015 and 2014 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 531	$ 242	$ (788)	$ 20	$ 5
Other	(8)	—	16	(36)	(28)
Internal	—	—	(133)	133	—
Total Revenues	523	242	(905)	117	(23)
Operating Expenses:					
Fuel	(34)	—	(391)	—	(425)
Purchased power	163	—	(694)	133	(398)
Other operating expenses	161	15	(405)	16	(213)
Pension and OPEB mark-to-market	(327)	1	(267)	—	(593)
Provision for depreciation	14	29	7	12	62
Amortization of regulatory assets, net	260	(4)	—	—	256
General taxes	10	32	(31)	5	16
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	255	73	(1,747)	166	(1,253)
Operating Income (Loss)	268	169	842	(49)	1,230
Other Income (Expense):					
Loss on debt redemptions	—	—	8	—	8
Investment income	(14)	—	(70)	(10)	(94)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	3	(30)	(3)	(29)	(59)
Capitalized financing costs	11	(11)	2	(3)	(1)
Total Other Expense	—	(41)	(63)	(404)	(508)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	268	128	779	(453)	722
Income taxes (benefits)	115	53	273	(84)	357
Income (Loss) From Continuing Operations	153	75	506	(369)	365
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income (Loss)	$ 153	$ 75	$ 420	$ (369)	$ 279

Regulated Distribution — 2015 Compared with 2014

Regulated Distribution's net income increased $153 million in 2015 compared to 2014, including a $327 million decrease in its Pension and OPEB mark-to-market adjustment. Excluding the impact of this adjustment, year-over-year earnings were impacted by increased operating expenses, including higher reliability maintenance expenses, higher benefit costs, and higher depreciation associated with increased capital investments, and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain operating companies.

Revenues —

The $523 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,993	$ 3,694	$ 299
Generation sales:			
Retail	4,303	4,043	260
Wholesale	508	661	(153)
Total generation sales	4,811	4,704	107
Transmission sales:			
Retail	513	352	161
Wholesale	112	148	(36)
Total transmission sales	625	500	125
Other	196	204	(8)
Total Revenues	$ 9,625	$ 9,102	$ 523

Distribution services revenues increased $299 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and for MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution services revenues increased resulting from the Ohio Companies' Rider DCR and higher cost recovery for above market NUG costs and certain energy efficiency programs for the Pennsylvania Companies, which was impacted by a rate increase in 2015. Partially offsetting these items were the impacts of lower residential and industrial customer usage as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	54,466	54,766	(0.5)%
Commercial	43,091	42,925	0.4 %
Industrial	50,269	51,276	(2.0)%
Other	585	586	(0.2)%
Total Electric Distribution MWH Deliveries	148,411	149,553	(0.8)%

Lower deliveries to residential customers, reflect declining weather-adjusted average customer usage due, in part, to increasing energy efficiency mandates as well as heating degree days that were 10.8% below the same period in 2014 and 2.8% below normal, partially offset by cooling degree days that were 32% above 2014 and 17% above normal. Commercial sales increased year-over -year from the increase in cooling degree days, partially offset by the lower heating degree days as well as decreased weather-adjusted usage due, in part, to increasing energy efficiency mandates. Deliveries to industrial customers decreased 2%, as the increase from shale and petroleum customer usage was more than offset by a decrease from steel and mining customer usage.

The following table summarizes the price and volume factors contributing to the $107 million increase in generation revenues in 2015 compared to 2014:

Source of Change in Generation Revenues		Increase (Decrease)
		(In millions)
Retail:		
Effect of increase in sales volumes	$	146
Change in prices		114
		260
Wholesale:		
Effect of decrease in sales volumes		(133)
Change in prices		(75)
Capacity revenue		55
		(153)
Increase in Generation Revenues	$	107

The increase in retail generation sales volume was primarily due to lower customer shopping in Ohio, Pennsylvania, and New Jersey and an increase in weather-related usage, partially offset by the impacts of energy efficiency as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 81% for the Ohio Companies, 65% from 67% for the Pennsylvania Companies and 50% from 52% for JCP&L. The increase in prices primarily resulted from higher default service auction results.

Wholesale generation revenues decreased $153 million in 2015 compared to 2014, primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch of fossil generating units associated with low spot market energy prices. Partially offsetting the decrease was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact on earnings.

The increase in retail transmission revenues of $161 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings. The decrease in wholesale transmission revenues of $36 million primarily relates to lower congestion revenue resulting from the impact of market conditions associated with the extreme weather and market conditions in 2014.

Operating Expenses —

Total operating expenses increased $255 million primarily due to the following:

- Fuel expense decreased $34 million in 2015 primarily related to lower economic dispatch resulting from low spot market energy prices.
- Purchased power costs were $163 million higher in 2015 primarily due to increased volumes reflecting lower customer shopping as described above, higher unit costs related to higher default service auction results, and higher capacity expense at MP, partially offset by lower purchases resulting from the termination of certain NUG contracts at JCP&L and PN.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 66
Change due to increased volumes	185
	251
Purchases from affiliates:	
Change due to decreased unit costs	(21)
Change due to decreased volumes	(113)
	(134)
Capacity expense	36
Amortization of deferred costs	10
Increase in Purchased Power Costs	$ 163

- Other operating expenses increased $161 million primarily due to:

  - Higher transmission expenses of $73 million primarily due to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The differences between current retail transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

  - Increased regulated generation operating and maintenance expenses of $7 million, reflecting higher planned outage expenses in 2015 compared to 2014.

  - Higher retirement benefit costs of $22 million, reflecting higher net benefit costs before the pension and OPEB mark-to-market adjustment described below.

  - Higher distribution operating and maintenance expenses of $54 million, reflecting increased reliability maintenance in New Jersey and the Pennsylvania companies and other employee benefit costs, partially offset by lower storm restoration costs.

- Pension and OPEB mark-to-market adjustment decreased $327 million to $179 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Depreciation expense increased $14 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L effective with the implementation of new rates from its distribution base rate case as well as lower depreciation rates in Pennsylvania based on updated asset life studies approved by the PPUC.

- Net regulatory asset amortization increased $260 million primarily due to:

  - Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($66 million),
  - Higher energy efficiency program cost recovery ($66 million),
  - Lower deferral of TTS costs in West Virginia ($37 million),
  - Higher amortizations of above-market NUG costs in Pennsylvania and New Jersey ($36 million),
  - Lower deferral of West Virginia vegetation management expenses ($31 million),
  - Higher default generation service cost amortization ($28 million), and
  - Recovery of Pennsylvania legacy meter costs ($22 million); partially offset by
  - Higher cost deferral of Ohio network transmission expenses ($33 million).

- General taxes increased $10 million primarily due to higher revenue-related taxes in Pennsylvania, partially offset by lower property taxes in Ohio.

Other Expense —

Other expense was flat in 2015 as compared to 2014, as lower investment income was offset by lower interest expense and higher capitalized financing costs.

Income Taxes —

Regulated Distribution's effective tax rate was 35.6% and 32.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Regulated Transmission — 2015 Compared with 2014

Net income increased $75 million in 2015 compared to 2014. Higher Transmission revenues associated with ATSI's "forward looking" rate and higher rate base were partially offset by higher interest expense and lower capitalized financing costs.

Revenues —

Total revenues increased $242 million principally at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2015	2014	Increase
		(In millions)	
ATSI	$ 446	$ 242	$ 204
TrAIL	252	214	38
PATH	13	13	—
Utilities	300	300	—
Total Revenues	$ 1,011	$ 769	$ 242

Operating Expenses —

Total operating expenses increased $73 million principally due to higher operating and maintenance expenses, depreciation, and property taxes at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expenses —

Other expenses increased $41 million due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings as well as lower capitalized financing costs.

Income Taxes —

Regulated Transmission's effective tax rate was 36.9% and 35.2% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

CES — 2015 Compared with 2014

Operating results increased $420 million in 2015 compared to 2014, primarily from higher capacity revenues and the absence of the impact of the high market prices associated with extreme weather events and unplanned outages in 2014 that resulted in higher purchased power and transmission costs, partially offset by lower contract sales volumes. Additionally, changes in year-over-year operating results were impacted by lower Pension and OPEB mark-to-market adjustments, lower settlement and termination costs related to coal and transportation contracts, and the absence of a $78 million after-tax gain on the sale of certain hydroelectric facilities recognized in February 2014.

Revenues —

Total revenues decreased $905 million in 2015, compared to 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing as well as higher capacity revenues, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 1,269	$ 2,359	$ (1,090)
Governmental Aggregation	1,012	1,184	(172)
Mass Market	265	452	(187)
POLR	712	902	(190)
Structured Sales	558	522	36
Total Contract Sales	3,816	5,419	(1,603)
Wholesale	1,225	461	764
Transmission	138	220	(82)
Other	205	189	16
Total Revenues	$ 5,384	$ 6,289	$ (905)

MWH Sales by Channel	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	23,585	44,012	(46.4)%
Governmental Aggregation	15,443	19,569	(21.1)%
Mass Market	3,878	6,773	(42.7)%
POLR	11,950	15,708	(23.9)%
Structured Sales	12,902	12,814	0.7 %
Total Contract Sales	67,758	98,876	(31.5)%
Wholesale	7,326	680	977.4 %
Total MWH Sales	75,084	99,556	(24.6)%

The following tables summarize the price and volume factors contributing to changes in revenues:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (1,095)	$ 5	$ —	$ —	$(1,090)
Governmental Aggregation	(249)	77	—	—	(172)
Mass Market	(193)	6	—	—	(187)
POLR	(216)	26	—	—	(190)
Structured Sales	3	33	—	—	36
Wholesale	197	(8)	107	468	764

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflect CES' efforts to more effectively hedge its generation by reducing exposure to weather-sensitive load. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price, partially offset by a lower energy component of the retail price resulting from lower year-over-year market prices. The Direct, Governmental Aggregation and Mass Market customer base was 1.6 million as of December 31, 2015, compared to 2.1 million as of December 31, 2014.

The decrease in POLR sales of $190 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $36 million due to low market prices that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $764 million primarily due to an increase in capacity revenue from higher capacity prices, increase in short-term (net hourly position) transactions, and higher net gains on financially settled contracts, partially offset by lower spot market energy prices which limited additional wholesale sales.

Transmission revenue decreased $82 million primarily due to lower congestion revenue resulting from the market conditions associated with the extreme weather events in 2014.

Other revenue increased $16 million primarily due to higher lease revenues from additional equity interests in affiliated sale and leasebacks repurchased in November 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,747 million in 2015 due to the following:

- Fuel costs decreased $391 million primarily due to lower economic dispatch of fossil units resulting from low spot market energy prices and lower nuclear unit prices, resulting from the suspension of the DOE nuclear disposal fee, effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. The impact of terminations and settlements of coal and transportation contracts resulted in a pre-tax loss of $67 million and $166 million in 2015 and 2014, respectively.

- Purchased power costs decreased $694 million due to lower volumes ($888 million), partially offset by higher unit prices ($39 million) and higher capacity expenses ($155 million). Lower volumes were primarily due to decreased load requirements resulting from lower sales as discussed above, partially offset by lower fossil generation as discussed above. The higher unit prices are primarily due to higher losses on financially settled contracts, partially offset by lower market prices in 2015 as compared to 2014. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Nuclear operating costs increased $84 million as a result of higher planned outage costs and higher employee benefit expenses. There were three planned refueling outages in 2015 as compared to two planned outages in 2014.

- Transmission expenses decreased $273 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in 2014.

- General taxes decreased $31 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Pension and OPEB mark-to-market adjustment decreased $267 million to $60 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Other operating expenses decreased $212 million primarily due to a $141 million decrease in mark-to-market expenses on commodity contract positions reflecting lower market prices and a $71 million decrease in retail-related costs.

- Impairments of long-lived assets increased $34 million due to impairment charges associated with non-core assets.

Other Expense —

Total other expense increased $63 million in 2015 compared to 2014 primarily due to higher OTTI on NDT investments, partially offset by the absence of an $8 million loss on debt redemptions incurred in 2014.

Discontinued Operations —

There were no discontinued operations in 2015. In 2014, discontinued operations primarily included a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of certain hydroelectric assets on February 12, 2014.

Income Taxes (Benefits) —

CES' effective tax rate was 36.0% and 34.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Corporate/Other — 2015 Compared with 2014

Financial results from Corporate/Other resulted in a $369 million decrease in net income in 2015 compared to 2014 primarily due to a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding, higher costs associated with environmental remediation at legacy plants, higher interest expense and a higher effective tax rate. During 2015, based on the significant decline in coal pricing and the current outlook for the coal market, FirstEnergy assessed the carrying value of its investment in Global Holding and determined there was an other than temporary decline in the fair value below its carrying value, which resulted in the impairment charge. The increased interest expense primarily relates to a $1 billion term loan entered into in March 2014 and a gain on the termination of interest rate swap arrangements recognized in 2014. The higher effective tax rate primarily resulted from the absence of tax benefits recognized in 2014 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, the elimination of certain tax liabilities associated with basis differences as well as certain tax benefits recorded in 2014 that related to prior periods.

Summary of Results of Operations — 2014 Compared with 2013

Financial results for FirstEnergy's business segments in 2014 and 2013 were as follows:

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized interest	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 731	$ 5,542	$ (161)	$ 14,611
Other	221	—	186	(126)	281
Internal	—	—	770	(770)	—
Total Revenues	8,720	731	6,498	(1,057)	14,892
Operating Expenses:					
Fuel	377	—	2,119	—	2,496
Purchased power	3,308	—	1,425	(770)	3,963
Other operating expenses	1,773	131	2,007	(318)	3,593
Pension and OPEB mark-to-market	(149)	—	(107)	—	(256)
Provision for depreciation	606	114	439	43	1,202
Amortization of regulatory assets, net	529	10	—	—	539
General taxes	697	54	202	25	978
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	7,463	309	6,558	(1,020)	13,310
Operating Income (Loss)	1,257	422	(60)	(37)	1,582
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	14	(38)	33
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized interest	31	14	42	16	103
Total Other Expense	(455)	(79)	(315)	(163)	(1,012)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	802	343	(375)	(200)	570
Income taxes (benefits)	301	129	(140)	(95)	195
Income From Continuing Operations	501	214	(235)	(105)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	$ 501	$ 214	$ (218)	$ (105)	$ 392

Changes Between 2014 and 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 399	$ 38	$ (261)	$ (32)	$ 144
Other	(17)	—	3	27	13
Internal	—	—	49	(49)	—
Total Revenues	382	38	(209)	(54)	157
Operating Expenses:					
Fuel	190	—	(406)	—	(216)
Purchased power	77	—	725	(49)	753
Other operating expenses	308	8	68	(15)	369
Pension and OPEB mark-to-market	655	2	434	—	1,091
Provision for depreciation	52	13	(52)	5	18
Amortization of regulatory assets, net	(528)	1	—	—	(527)
General taxes	(4)	16	(31)	3	(16)
Impairment of long-lived assets	(322)	—	(473)	—	(795)
Total Operating Expenses	428	40	265	(56)	677
Operating Income (Loss)	(46)	(2)	(474)	2	(520)
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(17)	124
Investment income	(1)	—	40	—	39
Interest expense	(46)	(38)	33	(6)	(57)
Capitalized interest	(17)	41	(5)	(4)	15
Total Other Expense	(64)	3	209	(27)	121
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	(110)	1	(265)	(25)	(399)
Income taxes (benefits)	(74)	(8)	(83)	(72)	(237)
Income (Loss) From Continuing Operations	(36)	9	(182)	47	(162)
Discontinued Operations, net of tax	—	—	69	—	69
Net Income (Loss)	$ (36)	$ 9	$ (113)	$ 47	$ (93)

Regulated Distribution — 2014 Compared with 2013

Regulated Distribution's net income decreased $36 million in 2014 compared to 2013. Regulated Distribution's Pension and OPEB mark-to-market adjustment increased $655 million which was partially offset by a reduction in regulatory asset impairment charges of $305 million and an impairment of long-lived assets of $322 million incurred in 2013. Excluding the impact of these charges, year-over-year earnings were impacted by higher distribution operating and maintenance costs, including the impact of higher benefit costs, higher depreciation and property taxes, and higher interest expense from debt issuances. These items were partially offset by slightly higher distribution deliveries, higher earnings associated with the October 2013 Harrison/Pleasants asset transfer, and a lower effective tax rate.

Revenues —

The $382 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,694	$ 3,762	$ (68)
Generation sales:			
Retail	4,043	3,959	84
Wholesale	661	330	331
Total generation sales	4,704	4,289	415
Transmission sales:			
Retail	352	347	5
Wholesale	148	101	47
Total transmission sales	500	448	52
Other	204	221	(17)
Total Revenues	$ 9,102	$ 8,720	$ 382

The decrease in distribution services revenue is primarily related to a decrease in revenues from ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency and other customer program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries of 1.1% as described below, rate increases for the Ohio Companies associated with energy efficiency performance shared savings and the Rider DCR, and higher revenues for the Pennsylvania Companies associated with the recovery of Smart Meter program costs. Certain Ohio energy efficiency programs permit the Ohio Companies to bill and collect shared savings revenues if energy efficiency programs meet or exceed the state mandates. Additionally, the Rider DCR provides for recovery of incremental operating expenses and a return on rate base associated with incremental distribution plant investments in Ohio. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2014	2013	Increase
	(In thousands)		
Residential	54,766	54,479	0.5%
Commercial	42,925	42,582	0.8%
Industrial	51,276	50,243	2.1%
Other	586	584	0.3%
Total Electric Distribution MWH Deliveries	149,553	147,888	1.1%

Higher deliveries to residential customers primarily reflect increased weather-related usage resulting from heating degree days that were 7% above 2013, and 9% above normal, partially offset by cooling degree days that were 15% below 2013, and 12% below normal. Increased deliveries to commercial customers reflect improving economic conditions across FirstEnergy's service territories. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical and paper customers.

The following table summarizes the price and volume factors contributing to the $415 million increase in generation revenues in 2014 compared to 2013:

Source of Change in Generation Revenues	**Increase**
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 14
Change in prices	70
	84
Wholesale:	
Effect of increase in sales volumes	166
Change in prices	79
Capacity revenue	86
	331
Increase in Generation Revenues	$ 415

The increase in retail generation sales volume was primarily due to weather-related usage, as described above, and improving economic conditions, partially offset by increased customer shopping in Pennsylvania. The increase in retail generation prices reflects higher Pennsylvania PTC prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact on retail generation prices of MP's Temporary Transaction Surcharge (TTS) associated with the October 2013 Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs. As part of the TTS, MP earns a return on and of the Harrison plant costs.

The increase in wholesale generation revenues of $331 million in 2014 resulted from increased volume and energy prices associated with market conditions related to extreme weather events in January 2014 and increased capacity revenue related to the October 2013 Harrison/Pleasants asset transfer whereby MP acquired from AE Supply 1,476 MWs of net capacity. During January 2014, unprecedented customer demand associated with prolonged periods of bitterly cold temperatures and unit unavailability across the PJM footprint resulted in severe market price volatility for electricity and natural gas throughout PJM. Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. The difference between wholesale generation revenues, primarily associated with MP's regulated generation, and certain energy costs are deferred for future recovery, with no material impact to earnings.

The increase in transmission revenues of $52 million reflects higher PJM revenues at MP associated with market conditions related to extreme weather events described above and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013 as discussed above. Network transmission costs are now recovered through WP's generation rate.

Other revenues decreased $17 million primarily due to less customer requested work in 2014 compared to 2013.

Operating Expenses —

Total operating expenses increased by $428 million primarily due to the following:

- Fuel expense was $190 million higher in 2014 primarily related to increased generation as a result of the October 2013 Harrison/Pleasants asset transfer.

- Purchased power costs were $77 million higher in 2014 primarily due to increased unit prices and capacity expense reflecting higher auction clearing prices, partially offset by a decrease in purchased volumes required.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 127
Change due to decreased volumes	(134)
	(7)
Purchases from affiliates:	
Change due to increased unit costs	39
Change due to increased volumes	2
	41
Capacity expense	58
Increase in costs deferred	(15)
Increase in Purchased Power Costs	$ 77

Other operating expenses increased $308 million primarily due to:

- Higher transmission expenses of $130 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of market conditions related to extreme weather events in January 2014 and higher PJM transmission costs resulting from the October 2013 Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

- Higher distribution operating and maintenance expenses of $75 million resulting from higher maintenance activities and storm related restoration expenses, including $26 million of storm expenses deferred for future recovery.

- Higher vegetation management expenses in West Virginia of $33 million, which were deferred for future recovery per authorization of the WVPSC.

- Higher retirement benefit costs of $33 million primarily reflecting higher net periodic benefit costs before the pension and OPEB mark-to-market adjustments discussed below.

- Increased regulated generation operating and maintenance expenses of $23 million, reflecting increased costs associated with the October 2013 Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Pension and OPEB mark-to-market adjustments increased $655 million to $506 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.

- Depreciation expense increased $52 million due to a higher asset base, including $22 million at MP associated with the October 2013 Harrison/Pleasants asset transfer.

- Net regulatory asset amortization decreased $528 million primarily due to:
  - Impairment charges on regulatory assets of $305 million associated with the recovery of marginal transmission losses at ME and PN ($254 million) and the recovery of RECs for the Ohio Companies ($51 million) that occurred in 2013,
  - Decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies ($67 million),
  - Lower default generation service and NUG costs recovery in Pennsylvania ($48 million),
  - Increased deferral of West Virginia vegetation management expenses ($33 million) and customer refunds associated with the gain on the Pleasants plant resulting from the October 2013 Harrison/Pleasants asset transfer ($36 million), and
  - Higher storm cost deferrals ($26 million).

- General taxes decreased $4 million primarily due to lower revenue-related taxes, partially offset by higher property taxes and an increase in the West Virginia business and occupation tax as a result of the October 2013 Harrison/Pleasants asset transfer.

- The 2013 impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of the Harrison plant to the amount permitted to be included in rate base as part of the October 2013 Harrison/Pleasants asset transfer.

Other Expense —

Other expense increased $64 million in 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the October 2013 Harrison/Pleasants asset transfer, a new debt issuance of $500 million in August 2013 at JCP&L and lower capitalized financing costs related primarily to a decrease in the rate used for borrowed funds.

Income Taxes —

Regulated Distribution's effective tax rate was 32.8% and 37.5% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in state flow through income tax benefits and other realized tax benefits.

Regulated Transmission — 2014 Compared with 2013

Net income increased $9 million in 2014 compared to 2013. Higher Transmission revenues associated with increased capital investments and higher capitalized financing costs were partially offset by higher operating expenses and interest expense.

Revenues —

Total revenues increased $38 million principally due to higher revenue at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base as included in their annual rate filings effective June 2013 and June 2014.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	**For the Years Ended December 31, 2014**	**2013**	**Increase (Decrease)**
		(In millions)	
ATSI	$ 242	$ 209	$ 33
TrAIL	214	207	7
PATH	13	20	(7)
Utilities	300	295	5
Total Revenues	$ 769	$ 731	$ 38

Operating Expenses —

Total operating expenses increased $40 million principally due to higher property taxes, depreciation and other operating expenses.

Other Expenses —

Total other expenses decreased $3 million principally due to higher capitalized financing costs of $41 million related to increased construction work in progress balances associated with the *Energizing the Future* investment plan, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings.

Income Taxes —

Regulated Transmission's effective tax rate was 35.2% and 37.6% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from an increase in AFUDC equity flow through.

CES — 2014 Compared with 2013

Operating results decreased $113 million in 2014, compared to 2013. Lower impairment charges of $473 million associated with the deactivation of the Hatfield and Mitchell generating units and a lower loss on debt redemptions of $141 million were partially offset with higher Pension and OPEB mark-to-market adjustments of $434 million. Excluding the impact of these charges, year-over-year earnings were impacted by lower sales volumes, reflecting CES' selling efforts discussed below and an increase in purchased power and transmission costs incurred to serve contract sales due to market conditions associated with the extreme weather events in January 2014. Partially offsetting these items were lower operating expenses due to lower retail-related costs, lower generation costs resulting from plant deactivations and asset transfers, and higher capacity revenues from higher auction prices. Additionally, operating results were impacted by a $78 million after-tax gain on the sale of certain hydro facilities in February 2014.

Revenues —

Total revenues decreased $209 million in 2014, compared to 2013, primarily due to decreased sales volumes in the Direct and Governmental Aggregation sales channels, partially offset by higher volume in the Structured Sales channel. Revenues were also impacted by higher unit prices as a result of increased channel pricing and higher capacity revenues, as described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 2,359	$ 2,913	$ (554)
Governmental Aggregation	1,184	1,185	(1)
Mass Market	452	448	4
POLR	902	858	44
Structured Sales	522	421	101
Total Contract Sales	5,419	5,825	(406)
Wholesale	461	343	118
Transmission	220	144	76
Other	189	186	3
Total Revenues	$ 6,289	$ 6,498	$ (209)

MWH Sales by Channel	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	44,012	56,145	(21.6)%
Governmental Aggregation	19,569	20,859	(6.2)%
Mass Market	6,773	6,761	0.2 %
POLR	15,708	15,758	(0.3)%
Structured Sales	12,814	9,047	41.6 %
Total Contract Sales	98,876	108,570	(8.9)%
Wholesale	680	1,250	(45.6)%
Total MWH Sales	99,556	109,820	(9.3)%

The following tables summarize the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	Source of Change in Revenues Increase (Decrease) (In millions)				
Direct	$ (629)	$ 75	$ —	$ —	$ (554)
Governmental Aggregation	(73)	72	—	—	(1)
Mass Market	1	3	—	—	4
POLR	(3)	47	—	—	44
Structured Sales	176	(75)	—	—	101
Wholesale	(17)	—	(21)	156	118

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects CES' efforts to more effectively hedge its generation by reducing exposure to weather sensitive load. Additionally, although unit pricing was higher year-over-year in the Direct, Governmental Aggregation and Mass Market channels noted above, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase in prices associated with capacity was partially offset by lower energy pricing built into the retail product at the time customers were acquired for 2014 sales. Beginning in the fourth quarter of 2011, when there was a significant decline in energy prices, CES' 2014 retail sales position was approximately 30% committed, whereas its 2013 retail sales position was approximately 60% committed, resulting in a greater proportion of 2014 sales and unit prices being impacted by the decline in the energy prices.

The increase in POLR revenues of $44 million was due to higher rates associated with the capacity expense component of the rate discussed above, partially offset by lower sales volumes. The increase in Structured Sales revenues of $101 million was due to higher sales volumes, partially offset by lower unit prices primarily due to market conditions related to extreme weather events in 2014 that reduced the gains on various structured financial sales contracts.

Wholesale revenues increased $118 million primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in Wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013.

Transmission revenue increased $76 million due to higher congestion revenue driven by market conditions related to extreme weather events in 2014, as discussed above.

Other revenue increased $3 million in 2014 as compared to 2013 as higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since 2013, partially offset by a $17 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate. CES earns lease revenue associated with the equity interests it has purchased.

Operating Expenses —

Total operating expenses increased $265 million in 2014 due to the following:

- Fuel costs decreased $406 million primarily due to lower generation volumes resulting from the October 2013 Harrison/ Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages as compared to the same period of 2013. Higher unit prices, primarily driven by increased peaking generation, was partially offset by the suspension of the DOE nuclear disposal fee, which was effective May 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. Terminations and settlements associated with damages on coal and transportation contracts were approximately $166 million and $128 million in 2014 and 2013, respectively.

- Purchased power costs increased $725 million due to higher volumes ($252 million), increased unit prices ($565 million) and higher capacity expenses ($311 million), partially offset by lower losses on financially settled contracts ($403 million). Higher purchased volumes were primarily due to lower available generation due to outages, the October 2013 Harrison/ Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by lower contract sales as described above. The increase in unit prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by lower losses on financially settled contracts. The increase in capacity expense, which is a component of the segment's retail price, was primarily the result of higher capacity rates associated with the segment's retail sales obligations.

- Fossil operating costs decreased $73 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the October 2013 Harrison/Pleasants asset transfer.
- Nuclear operating costs increased $6 million as a result of higher labor, contractor, materials and equipment costs. There were two refueling outages in each of 2014 and 2013, however, the duration of the outages in 2014 exceeded the prior year.
- Transmission expenses increased $80 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in 2014. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.
- General taxes decreased $31 million primarily due to lower gross receipts taxes resulting from reduced retail sales volumes, lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the October 2013 Harrison/Pleasants asset transfer, and reduced Ohio personal property taxes.
- Impairments of long-lived assets decreased $473 million due to the impairment of two unregulated, coal-fired generating plants recognized in 2013.
- Depreciation expense decreased $52 million primarily due to a reduction in the asset base as a result of the plant deactivations and the October 2013 Harrison/Pleasants asset transfer noted above.
- Pension and OPEB mark-to-market adjustments increased $434 million to $327 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.
- Other operating expenses increased $55 million primarily due to an increase in mark-to-market expenses on commodity contract positions, and an impairment of deferred advertising costs of $23 million associated with the elimination of future selling efforts in the Mass Market and certain Direct sales channels, partially offset by lower retail and marketing related costs.

Other Expense —

Total other expense in 2014 decreased $209 million compared to 2013 due to the absence of a $141 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, higher investment income primarily on the NDT investments, lower OTTI and lower net interest expense of $28 million due to debt redemptions.

Income Tax Benefits —

CES' effective tax rate was 34.8% and 37.3% for 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pre-tax losses, primarily resulted from changes in state apportionment factors and higher valuation allowances on certain NOL carryforwards.

Discontinued Operations —

Discontinued operations increased $69 million in 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of hydro assets in February 2014.

Corporate/Other — 2014 Compared with 2013

Financial results from Corporate/Other resulted in a $47 million increase in net income in 2014 compared to 2013 primarily due to higher tax benefits, partially offset by $17 million of gains on debt redemptions in 2013. The higher tax benefits primarily resulted from an IRS-approved change in accounting method that increased the tax basis of certain assets resulting in higher future tax deductions, and the resolution of state tax benefits resulting from the expiration of the statute of limitation on certain state tax positions. Additional income tax benefits of $25 million were recognized in 2014 that relate to prior periods. The out-of-period adjustment primarily related to the correction of amounts included on FirstEnergy's tax basis balance sheet. Management has determined that these adjustments are not material to the current or any prior period. The 2013 effective tax rate benefited from reductions to valuation allowances against state NOL carryforwards, as well as changes in state apportionment factors, which reduced deferred tax liabilities.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets (Liabilities) by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest payments, dividend payments, and contributions to its pension plan. During 2015, FirstEnergy received $630 million of cash dividends and capital returned from its subsidiaries and paid $607 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2016 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

Additionally in 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses. With the exception of Regulated Transmission's 2016 projected capital expenditures discussed below, planned capital expenditures for 2016 for Regulated Distribution, CES, and Corporate/Other will depend on the outcome of the Ohio Companies' ESP IV and remain subject to Board approval.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion *Energizing the Future* investment plan that began in 2014 and will continue through 2017 to upgrade and expand FirstEnergy's transmission system. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. In total, FirstEnergy has identified at least $15 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

In alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments and the repositioning of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Any financing plans by FirstEnergy, including the issuance of equity, refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such issuances, financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of December 31, 2015, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2015, included the following:

Currently Payable Long-Term Debt	***(In millions)***
PCRBs supported by bank LOCs (1)	$ 92
FMBs	245
Unsecured notes	300
Unsecured PCRBs (1)	391
Collateralized lease obligation bonds	23
Sinking fund requirements	87
Other notes	28
	$ 1,166

(1) These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings / Revolving Credit Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy(1)	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET(2)	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2015:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)			
FE	$ 3,500	$ —	$ —	$ — (1)
FES	—	1,500	—	— (2)
AE Supply	—	1,000	—	— (2)
FET	—	—	1,000	— (1)
OE	500	—	—	500 (3)
CEI	500	—	—	500 (3)
TE	500	—	—	500 (3)
JCP&L	600	—	—	500 (3)
ME	300	—	—	500 (3)
PN	300	—	—	300 (3)
WP	200	—	—	200 (3)
MP	500	—	—	500 (3)
PE	150	—	—	150 (3)
ATSI	—	—	500	500 (3)
Penn	50	—	—	100 (3)
TrAIL	—	—	400	400 (3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of December 31, 2015 were issued by the following bank:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	$ 92	March 2017	March 2017

[1] Excludes approximately $1 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of December 31, 2015:

	Senior Secured		Senior Unsecured		
Issuer	**S&P**	**Moody's**	**S&P**	**Moody's**	**Fitch**
FE	—	—	BB+	Baa3	BB+
FES	BBB-	—	BBB-	Baa3	—
AE Supply	BBB-	—	BBB-	Baa3	—
AGC	—	—	BBB-	Baa3	—
ATSI	—	—	BBB-	Baa2	—
CEI	BBB+	Baa1	BBB-	Baa3	—
FET	—	—	BB+	Baa3	
JCP&L	—	—	BBB-	Baa2	—
ME	—	—	BBB-	Baa1	—
MP	BBB+	A3	—	—	—
OE	BBB+	A2	BBB-	Baa1	—
PN	—	—	BBB-	Baa2	—
Penn	—	A2	—	—	—
PE	BBB+	A3	—	—	—
TE	BBB	Baa1	—	—	—
TrAIL	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2015, FE and its subsidiaries could issue additional debt of approximately $5.1 billion and remain within the limitations of the financial covenants required by the Facilities. As of December 31, 2015, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.1 billion given FE's consolidated debt to total capitalization ratio under the FE Facility.

Changes in Cash Position

As of December 31, 2015, FirstEnergy had $131 million of cash and cash equivalents compared to $85 million of cash and cash equivalents as of December 31, 2014. As of December 31, 2015 and 2014, FirstEnergy had approximately $82 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are derived from electric services provided by its utility operating subsidiaries and the sale of energy and related products and services by its unregulated competitive subsidiaries. The most significant use of cash from operating activities is to buy electricity in the wholesale market and pay fuel suppliers, interest, employees, tax authorities, lenders and others for a wide range of materials and services.

Net cash provided from operating activities was $3,447 million during 2015, $2,713 million during 2014 and $2,662 million during 2013. Cash flows from operations increased $734 million in 2015 compared with 2014 due to the following:

- Distribution rate increases associated with the implementation of new rates, partially offset by a year-over-year decline in distribution deliveries;
- Higher transmission revenue and earnings, reflecting recovery of incremental operating expenses, a higher rate base and forward-looking rates at ATSI;
- Higher capacity revenues at CES, partially offset by a decline in sales volume;
- Lower disbursements for fuel and purchased power resulting from the lower sales volumes; and
- Lower posted collateral; partially offset by,
- A $143 million contribution to the qualified pension plan in 2015.

Cash Flows From Financing Activities

In 2015, cash used for financing activities was $279 million compared to $513 million and $477 million of net cash provided from financing activities during 2014 and 2013, respectively. The following table summarizes new debt financing (net of any discounts), redemptions and common stock dividend payments:

Securities Issued or Redeemed / Repaid	For the Years Ended December 31, 2015	2014	2013
		(In millions)	
New Issues			
Unsecured notes	$ 475	$ 2,400	$ 2,300
PCRBs	339	878	—
FMBs	295	200	1,000
Term loan	200	1,050	—
Senior secured notes	2	—	445
	$ 1,311	$ 4,528	$ 3,745
Redemptions / Repayments			
Unsecured notes	$ —	$ (600)	$ (2,284)
PCRBs	(313)	(793)	(470)
FMBs	(215)	(175)	(420)
Term loan	(200)	—	—
Senior secured notes	(151)	(191)	(376)
Long-term revolving credit	—	—	(50)
	$ (879)	$ (1,759)	$ (3,600)
Tender premiums paid on debt redemptions	$ —	$ —	$ (110)
Short-term borrowings, net	$ (91)	$ (1,605)	$ 1,435
Common stock dividend payments	$ (607)	$ (604)	$ (920)

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used:

(i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

Cash Flows From Investing Activities

Cash used for investing activities in 2015 principally represented cash used for property additions. The following table summarizes investing activities for 2015, 2014 and 2013:

Cash Used for Investing Activities	**For the Years Ended December 31, 2015**	**2014**	**2013**
		(In millions)	
Property Additions:			
Regulated distribution	$ 1,108	$ 972	$ 1,272
Regulated transmission	952	1,329	461
Competitive energy services	588	939	827
Other and reconciling adjustments	56	72	78
Nuclear fuel	190	233	250
Proceeds from asset sales	(20)	(394)	(4)
Investments	107	68	72
Asset removal costs	142	153	146
Other	(1)	(13)	(9)
	$ 3,122	$ 3,359	$ 3,093

Cash used for investing activity in 2015 as compared to 2014 were impacted by lower property additions of $608 million, partially offset by a $374 million reduction in proceeds received from asset sales, as 2014 included proceeds from the sale of certain hydroelectric assets. The decline in property additions were due to the following:

- a decrease of $351 million at CES, resulting from the absence of capital investments associated with the Davis-Besse steam generators that were placed into service in May 2014,
- a decrease of $377 million at Regulated Transmission primarily relating to the timing of capital investments associated with its *Energizing the Future* investment program, partially offset by
- an increase of $136 million at Regulated Distribution relating to utility specific project investments and costs associated with the Pennsylvania smart meter program.

CONTRACTUAL OBLIGATIONS

As of December 31, 2015, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	**Total**	**2016**	**2017-2018**	**2019-2020**	**Thereafter**
			(In millions)		
Long-term debt(1)	$ 20,238	$ 1,039	$ 3,435	$ 3,499	$ 12,265
Short-term borrowings	1,708	1,708	—	—	—
Interest on long-term debt(2)	12,523	1,015	1,839	1,500	8,169
Operating leases(3)	2,083	184	254	207	1,438
Capital leases(3)	150	36	55	32	27
Fuel and purchased power(4)	13,578	1,812	2,539	2,117	7,110
Capital expenditures (5)	2,213	877	938	398	—
Pension funding	3,564	381	1,122	787	1,274
Total	$ 56,057	$ 7,052	$ 10,182	$ 8,540	$ 30,283

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and capital leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2015.
(3) See Note 6, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Amounts represent committed capital expenditures as of December 31, 2015.

Excluded from the table above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $3.5 billion in 2016, $0.5 billion of which are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 14, Regulatory Matters), AROs (see Note 13, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 15, Commitments, Guarantees and Contingencies) since the amount and timing of the cash payments are uncertain. The table also excludes accumulated deferred income taxes and investment tax credits since cash payments for income taxes are determined based primarily on taxable income for each applicable fiscal year.

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $15 million (NG-$15.1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $83 million (NG-$81 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2015, was approximately $3.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$ 33
Deferred compensation arrangements	533
Other(2)	17
	583
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts(3)	251
FES' guarantee of NG's nuclear property insurance	98
FES' guarantee of nuclear decommissioning costs	21
FES' guarantee of FG's sale and leaseback obligations	1,767
	2,137
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	398
Surety Bonds	22
FES' LOC (long-term tax-exempt debt)(4)	93
LOCs(5)	154
	667
Total Guarantees and Other Assurances	$ 3,687

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.
(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $7 million for railcar leases, and $6 million for various leases.
(3) Includes energy and energy-related contracts associated with FES of approximately $248 million.
(4) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.
(5) Includes $54 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $88 million issued in connection with energy and energy related contracts, $2 million issued in connection with railcar leases, $7 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 by OE and $3 million pledged in connection with the sale and leaseback of Perry by OE.

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $8 million with affiliated parties.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $950 million as of December 31, 2015 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. In November 2014, NG repurchased lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative assets and liabilities as of December 31, 2015 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$ (6)	$ 1	$ —	$ —	$ —	$ —	$ (5)
Other external sources[2]	18	(1)	(21)	(26)	—	—	(30)
Prices based on models	(4)	2	—	—	(7)	—	(9)
Total[3]	$ 8	$ 2	$ (21)	$ (26)	$ (7)	$ —	$ (44)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(136) million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts as of December 31, 2015, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next 12 months.

Equity Price Risk

As of December 31, 2015, the FirstEnergy pension and OPEB plan assets were approximately allocated as follows: 41% in equity securities, 35% in fixed income securities, 6% in absolute return strategies, 10% in real estate and 8% in cash and short-term securities. A decline in the value of plan assets could result in additional funding requirements. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made a $143 million contribution to its qualified pension plan. See Note 3, Pension and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2015, FirstEnergy's pension plan and OPEB assets incurred losses of $(172) million, or (2.7)%, as compared to an expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG's and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2015, approximately 68% of the funds were invested in fixed income securities, 25% of the funds were invested in equity securities and 7% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,552 million, $576 million and $147 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2015, excluding $7 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $58 million reduction in fair value as of December 31, 2015. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT funds or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2015, FirstEnergy contributed approximately $15 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2016	2017	2018	2019	2020	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 5	$ 2	$ —	$ —	$ —	$ 1,794	$ 1,801	$ 1,802
Average interest rate	8.9%	8.9%	—%	—%	—%	3.6%	3.6%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 660	$ 1,517	$ 1,330	$ 1,035	$ 541	$ 13,867	$ 18,950	$ 20,225
Average interest rate	5.5%	6.1%	4.8%	6.5%	5.5%	5.2%	5.3%	
Variable rate	$ —	$ 2	$ 6	$ 1,000	$ 200	$ 86	$ 1,294	$ 1,294
Average interest rate	—%	3.5%	—%	2.2%	1.9%	—%	2.0%	

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specific collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of offset. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. The majority of FirstEnergy's energy contract counterparties maintain investment-grade credit ratings.

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;
- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015.The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;

- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015 and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, NG, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield's Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2015 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 14, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underlying the amounts included in the financial statements. Additional information regarding the application of accounting policies is included in the Combined Notes to Consolidated Financial Statements.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class. See Note 1, Organization and Basis of Presentation for additional details.

Regulatory Accounting

FirstEnergy's regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 14, Regulatory Matters for additional information.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings.

Pension and OPEB Accounting

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels.

FirstEnergy provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2015 was $4.0 billion.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pension were 4.50%, 4.25% and 5.00% as of December 31, 2015, 2014 and 2013, respectively. The assumed discount rates for OPEB were 4.25%, 4.00% and 4.75% as of December 31, 2015, 2014 and 2013, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million or (2.7)% compared to $387 million, or 6.2% in 2014 and losses of $(22) million, or (0.3)% in 2013 and assumed a 7.75% rate of return for both years on plan assets which generated $476 million, $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement. The expected return on plan assets for 2016 was lowered to 7.50%.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of $49 million and $1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.50% for pension, 4.25% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2016 pre-tax net periodic benefit cost (including amounts capitalized) to be approximately $122 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2016). The following table reflects the portion of pension and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2015.

Postemployment Benefits Expense (Credits)	**2015**	**2014**	**2013**
		(In millions)	
Pension	$ 316	$ 939	$ (134)
OPEB	(61)	(101)	(196)
Total	$ 255	$ 838	$ (330)

Health care cost trends continue to increase and will affect future OPEB costs. The 2015 composite health care trend rate assumptions were approximately 6.0-5.5%, compared to 7.5-7.0% in 2014, gradually decreasing to 4.5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effects on 2016 pension and OPEB net periodic benefit costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	**Adverse Change**	**Pension**	**OPEB**	**Total**
			(In millions)	
Discount rate	Decrease by .25%	273	19	$ 292
Long-term return on assets	Decrease by .25%	13	1	$ 14
Health care trend rate	Increase by 1.0%	N/A	25	$ 25

Please see Note 3, Pension and Other Postemployment Benefits for additional information

Long-Lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value. See Note 1, Organization and Basis of Presentation.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, Asset Retirement Obligations.

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. See Note 5, Taxes for additional information.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50%) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair values of these reporting units were, more likely than not, greater than their carrying values and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.

- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital, and revised environmental requirements could have a negative impact on future goodwill assessments.

See Note 1, Organization and Basis of Presentation for additional details.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

FIRSTENERGY SOLUTIONS CORP.

**MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS**

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG and the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States. In 2016 and going forward, FES expects to target approximately 65 to 75 million MWHs in annual contract sales with a projected target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct),10 to 20 million MWHs in block wholesale sales, including Structured sales, and 10 to 20 million MWHs of spot wholesale sales. As of December 31, 2015, committed contract sales for calendar year 2016 and 2017 were 61 million MWHs and 38 million MWHs, respectively.

FES is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and DR programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

For additional information with respect to FES, please see the information contained in FirstEnergy's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: FirstEnergy's Business and Executive Summary, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Operating results increased $326 million in 2015 compared to 2014. In 2014, FES sold certain hydroelectric power stations resulting in an after-tax gain of $110 million. Excluding the impact of this gain as well as the impact of lower Pension and OPEB mark-to-market adjustments, year-over-year operating results improved primarily from higher capacity revenue and the absence of the impact of the high market prices associated with extreme weather events and unplanned outages in 2014 that resulted in higher purchased power and transmission costs, partially offset by lower contract sales volumes.

Revenues -

Total revenues decreased $1,139 million in 2015, compared to 2014, primarily due to decreased sales volumes in line with FES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 1,269	$ 2,356	$ (1,087)
Governmental Aggregation	1,012	1,184	(172)
Mass Market	265	452	(187)
POLR	712	893	(181)
Structured Sales	535	498	37
Total Contract Sales	3,793	5,383	(1,590)
Wholesale	902	394	508
Transmission	122	198	(76)
Other	188	169	19
Total Revenues	$ 5,005	$ 6,144	$ (1,139)

MWH Sales by Channel	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	23,585	43,961	(46.4)%
Governmental Aggregation	15,443	19,569	(21.1)%
Mass Market	3,878	6,773	(42.7)%
POLR	11,950	15,559	(23.2)%
Structured Sales	12,486	12,393	0.8 %
Total Contract Sales	67,342	98,255	(31.5)%
Wholesale	2,188	14	15,528.6 %
Total MWH Sales	69,530	98,269	(29.2)%

The following table summarizes the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	Source of Change in Revenues Increase (Decrease) (In millions)				
Direct	$ (1,092)	$ 5	$ —	$ —	$ (1,087)
Governmental Aggregation	(249)	77	—	—	(172)
Mass Market	(193)	6	—	—	(187)
POLR	(207)	26	—	—	(181)
Structured Sales	4	33	—	—	37
Wholesale	62	(11)	34	423	508

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflect FES' efforts to more effectively hedge its generation by reducing exposure to weather-sensitive load. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price, partially offset by a lower energy component of the retail price resulting from lower year-over-year market prices. The Direct, Governmental Aggregation and Mass Market customer base was 1.6 million as of December 31, 2015, compared to 2.1 million as of December 31, 2014.

The decrease in POLR sales of $181 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $37 million primarily due to low market prices that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $508 million due to an increase in capacity revenue from higher capacity prices, an increase in short-term (net hourly position) transactions and higher net gains on financially settled contracts, partially offset by lower spot market energy prices which limited additional wholesale sales.

Transmission revenue decreased $76 million primarily due to lower congestion revenue resulting from the market conditions associated with the extreme weather events in 2014.

Other revenue increased $19 million primarily due to higher lease revenues from additional equity interests in affiliated sale and leasebacks repurchased in November 2014. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses decreased by $1,946 million in 2015 compared to 2014.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in 2015 compared with 2014:

Operating Expense	Volumes	Prices	Loss on Settled Contracts	Capacity Expense	Total
	Source of Change Increase (Decrease) (In millions)				
Fossil Fuel	$ (212)	$ (14)	$ (150)	$ —	$ (376)
Nuclear Fuel	5	(11)	—	—	(6)
Affiliated Purchased Power	(8)	22	68	—	82
Non-affiliated Purchased Power[1]	(1,477)	(259)	496	153	(1,087)

[1] In 2014, realized losses on financially settled wholesale sales contracts of $252 million resulting from higher market prices were netted in purchased power.

Fossil and nuclear fuel costs decreased $382 million, primarily due to lower economic dispatch of fossil units resulting from low spot market energy prices and an increase in fossil outages. Lower unit prices also contributed to the decrease, resulting from the suspension of the DOE nuclear disposal fee, effective May 16, 2014, and lower unit prices for coal. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. In 2015, a pre-tax gain of approximately $12 million was recognized associated with the elimination of an obligation under an existing coal contract. In 2014, terminations and settlements associated with damages on coal and transportation contracts resulted in a pre-tax loss of $138 million as compared to no charges in 2015.

Affiliated purchased power costs increased $82 million primarily associated with net losses on financially settled contracts with AE Supply resulting from lower market prices in 2015 as compared to 2014.

Non-affiliated purchased power costs decreased $1,087 million due to lower volumes ($1,256 million), partially offset by increased prices, net of financials ($16 million) and higher capacity expenses ($153 million). The higher unit prices are primarily due to higher losses on financially settled contracts, partially offset by lower market prices in 2015 as compared to 2014. Lower volumes were primarily due to decreased load requirements resulting from lower sales as discussed above, partially offset by decreased fossil generation as discussed above. The increase in capacity expense, which is a component of FES' retail price, was primarily the result of higher capacity rates associated with FES' retail sales obligations.

Other operating expenses decreased $294 million in 2015, compared to 2014 due to the following:

- Nuclear operating costs increased $84 million as a result of higher planned outage costs and higher employee benefit expenses. There were three planned refueling outages in 2015 as compared to two planned outages in 2014.
- Transmission expenses decreased $185 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in 2014.
- Other operating expenses decreased $186 million primarily due to a $142 million decrease in mark-to-market expenses on commodity contract positions reflecting lower market prices and a $78 million decrease in retail-related costs, partially offset by a $34 million impairment charge associated with non-core assets.

Pension and OPEB mark-to-market adjustment decreased $240 million to $57 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

General taxes decreased $30 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

Other Expense -

Total other expense increased $72 million in 2015 compared to 2014, primarily due to higher OTTI on NDT investments, partially offset by the absence of a $6 million loss on debt redemptions incurred in 2014.

Discontinued Operations -

There were no discontinued operations in 2015. In 2014, discontinued operations primarily included a pre-tax gain of approximately $177 million ($116 million after-tax) associated with the sale of certain hydroelectric facilities on February 12, 2014.

Income Taxes (Benefits) -

FES' effective tax rate was 44.2% and 38.8% in 2015 and 2014, respectively. The increase in the effective tax rate is primarily due to an increase in reserves associated with uncertain tax positions and the absence of tax benefits recognized in 2014 associated with changes to state apportionment factors, partially offset by lower valuation allowances recorded on state and municipal NOL carryforwards.

Market Risk Information

FES uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FES is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FES uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

Sources of information for the valuation of commodity derivative contracts assets and liabilities as of December 31, 2015 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2016	2017	2018	2019	2020	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ (6)	$ 1	$ —	$ —	$ —	$ —	$ (5)
Other external sources[2]	61	29	9	—	—	—	99
Prices based on models	(5)	2	—	—	—	—	(3)
Total	$ 50	$ 32	$ 9	$ —	$ —	$ —	$ 91

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.

FES performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2015, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next 12 months.

Interest Rate Risk

FES' exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for FES' investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2016	2017	2018	2019	2020	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ —	$ —	$ —	$ —	$ —	$ 810	$ 810	$ 810
Average interest rate	—%	—%	—%	—%	—%	4.2%	4.2%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 23	$ 34	$ 141	$ 90	$ 177	$ 2,468	$ 2,933	$ 3,027
Average interest rate	9.0%	3.2%	5.6%	3.0%	5.7%	4.4%	4.5%	
Variable rate	$ —	$ 2	$ 6	$ —	$ —	$ 86	$ 94	$ 94
Average interest rate	—%	3.5%	—%	—%	—%	—%	0.1%	

Equity Price Risk

NDT funds have been established to satisfy NG's nuclear decommissioning obligations. Included in FES' NDT are fixed income, equities and short-term investments carried at market values of approximately $810 million, $378 million and $137 million, respectively, as of December 31, 2015, excluding $2 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $38 million reduction in fair value as of December 31, 2015. NG recognizes in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FES' NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements.

Credit Risk

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FES evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FES may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FES monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FES measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FES has a legally enforceable right of offset. FES monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. The majority of FES' energy contract counterparties maintain investment-grade credit ratings.

Retail Credit Risk

FES' principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FES' retail credit risk may be adversely impacted.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A relating to market risk is set forth in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2015 consolidated financial statements as stated in their audit report included herein.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2015.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework published in 2013, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2015. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2015 consolidated financial statements as stated in their audit report included herein.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy Corp.'s Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2015.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework published in 2013, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2015.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Corp. 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 Item15(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 *Internal Control - Integrated Framework (2013)* 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 1 to the consolidated financial statements, in 2015 the Company changed the manner in which deferred tax assets and liabilities, along with any related valuation allowance, are classified on the balance sheet.

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2016

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of Directors of FirstEnergy Solutions Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. 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 financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2016

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(In millions)	**2015**	**2014**	**2013**
REVENUES:			
Electric utilities	$ 10,636	$ 9,871	$ 9,451
Unregulated businesses	4,390	5,178	5,441
Total revenues*	15,026	15,049	14,892
OPERATING EXPENSES:			
Fuel	1,855	2,280	2,496
Purchased power	4,318	4,716	3,963
Other operating expenses	3,749	3,962	3,593
Pension and OPEB mark-to-market adjustment	242	835	(256)
Provision for depreciation	1,282	1,220	1,202
Amortization of regulatory assets, net	268	12	539
General taxes	978	962	978
Impairment of long-lived assets	42	—	795
Total operating expenses	12,734	13,987	13,310
OPERATING INCOME	2,292	1,062	1,582
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	—	(8)	(132)
Investment income (loss)	(22)	72	33
Impairment of equity method investment	(362)	—	—
Interest expense	(1,132)	(1,073)	(1,016)
Capitalized financing costs	117	118	103
Total other expense	(1,399)	(891)	(1,012)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570
INCOME TAXES (BENEFITS)	315	(42)	195
INCOME FROM CONTINUING OPERATIONS	578	213	375
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17
NET INCOME	$ 578	$ 299	$ 392
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Basic - Discontinued Operations (Note 19)	—	0.20	0.04
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	422	420	418
Diluted	424	421	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.44	$ 1.44	$ 1.65

* Includes excise tax collections of $416 million, $420 million and $458 million in 2015, 2014 and 2013, respectively.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(In millions)	2015	2014	2013
NET INCOME	$ 578	$ 299	$ 392
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(116)	(76)	(160)
Amortized gains (losses) on derivative hedges	5	(2)	3
Change in unrealized gain on available-for-sale securities	(11)	26	(10)
Other comprehensive loss	(122)	(52)	(167)
Income tax benefits on other comprehensive loss	(47)	(14)	(66)
Other comprehensive loss, net of tax	(75)	(38)	(101)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 503	$ 261	$ 291

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

Met-Ed Exhibit JD-15
Attachment A
Witness: J. Dipre

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 131	$ 85
Receivables-		
Customers, net of allowance for uncollectible accounts of $69 in 2015 and $59 in 2014	1,415	1,554
Other, net of allowance for uncollectible accounts of $5 in 2015 and 2014	180	225
Materials and supplies, at average cost	785	817
Prepaid taxes	135	128
Derivatives	157	159
Collateral	70	230
Other	167	160
	3,040	3,358
PROPERTY, PLANT AND EQUIPMENT:		
In service	49,952	47,484
Less — Accumulated provision for depreciation	15,160	14,150
	34,792	33,334
Construction work in progress	2,422	2,449
	37,214	35,783
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,282	2,341
Other	506	881
	2,788	3,222
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,348	1,411
Other	1,379	1,456
	9,145	9,285
	$ 52,187	$ 51,648
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,166	$ 804
Short-term borrowings	1,708	1,799
Accounts payable	1,075	1,279
Accrued taxes	519	490
Accrued compensation and benefits	334	329
Derivatives	106	167
Other	694	693
	5,602	5,561
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 423,560,397 and 421,102,570 shares outstanding as of December 31, 2015 and December 31, 2014, respectively	42	42
Other paid-in capital	9,952	9,847
Accumulated other comprehensive income	171	246
Retained earnings	2,256	2,285
Total common stockholders' equity	12,421	12,420
Noncontrolling interest	1	2
Total equity	12,422	12,422
Long-term debt and other long-term obligations	19,192	19,176
	31,614	31,598
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,773	6,539
Retirement benefits	4,245	3,932
Asset retirement obligations	1,410	1,387
Deferred gain on sale and leaseback transaction	791	824
Adverse power contract liability	197	217
Other	1,555	1,590
	14,971	14,489
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$ 52,187	$ 51,648

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(In millions, except share amounts)	Common Stock: Number of Shares	Common Stock: Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
Balance, January 1, 2013	418,216,437	$ 42	$ 9,769	$ 385	$ 2,888
Net income					392
Amortized losses on derivative hedges, net of $1 million of income taxes				2	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(6)	
Pension and OPEB, net of $63 million of income tax benefits (Note 3)				(97)	
Stock-based compensation			(4)		
Cash dividends declared on common stock					(690)
Stock issuance - employee benefits	412,122		11		
Balance, December 31, 2013	418,628,559	42	9,776	284	2,590
Net income					299
Amortized gains on derivative hedges, net of $1 million of income tax benefits				(1)	
Change in unrealized gain on investments, net of $10 million of income taxes				16	
Pension and OPEB, net of $23 million of income tax benefits (Note 3)				(53)	
Stock-based compensation			20		
Cash dividends declared on common stock					(604)
Stock issuance - employee benefits	2,474,011		51		
Balance, December 31, 2014	421,102,570	42	9,847	246	2,285
Net income					578
Amortized gains on derivative hedges, net of $1 million of income taxes				4	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(7)	
Pension and OPEB, net of $44 million of income tax benefits (Note 3)				(72)	
Stock-based compensation			45		
Cash dividends declared on common stock					(607)
Stock issuance - employee benefits	2,457,827		60		
Balance, December 31, 2015	423,560,397	$ 42	$ 9,952	$ 171	$ 2,256

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In millions)	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 578	$ 299	$ 392
Adjustments to reconcile net income to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, regulatory assets, net, and customer intangible amortization	1,836	1,563	2,022
Impairments of long-lived assets	42	—	795
Investment impairment, including equity method investment	464	37	90
Pension and OPEB mark-to-market adjustment	242	835	(256)
Deferred income taxes and investment tax credits, net	284	162	243
Deferred costs on sale leaseback transaction, net	48	48	48
Deferred purchased power and other costs	(105)	(115)	(76)
Asset removal costs charged to income	55	28	20
Retirement benefits	(20)	(53)	(168)
Commodity derivative transactions, net (Note 10)	(73)	64	(3)
Pension trust contributions	(143)	—	—
Gain on sale of investment securities held in trusts	(23)	(64)	(56)
Loss on debt redemptions	—	8	132
Make-whole premiums paid on debt redemptions	—	—	(187)
Lease payments on sale and leaseback transaction	(131)	(137)	(136)
Income from discontinued operations (Note 19)	—	(86)	(17)
Changes in current assets and liabilities-			
Receivables	184	139	(114)
Materials and supplies	(15)	(65)	96
Prepayments and other current assets	(10)	126	(126)
Accounts payable	(243)	42	(25)
Accrued taxes	29	(165)	85
Accrued interest	(6)	31	(10)
Accrued compensation and benefits	5	(22)	19
Other current liabilities	75	23	(62)
Cash collateral, net	140	(54)	(36)
Other	234	69	(8)
Net cash provided from operating activities	3,447	2,713	2,662
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,311	4,528	3,745
Short-term borrowings, net	—	—	1,435
Redemptions and Repayments-			
Long-term debt	(879)	(1,759)	(3,600)
Short-term borrowings, net	(91)	(1,605)	—
Tender premiums paid on debt redemptions	—	—	(110)
Common stock dividend payments	(607)	(604)	(920)
Other	(13)	(47)	(73)
Net cash (used for) provided from financing activities	(279)	513	477
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,704)	(3,312)	(2,638)
Nuclear fuel	(190)	(233)	(250)
Proceeds from asset sales	20	394	4
Sales of investment securities held in trusts	1,534	2,133	2,047
Purchases of investment securities held in trusts	(1,648)	(2,236)	(2,096)
Cash investments	7	35	(23)
Asset removal costs	(142)	(153)	(146)
Other	1	13	9
Net cash used for investing activities	(3,122)	(3,359)	(3,093)
Net change in cash and cash equivalents	46	(133)	46
Cash and cash equivalents at beginning of period	85	218	172
Cash and cash equivalents at end of period	$ 131	$ 85	$ 218
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 1,028	$ 931	$ 969
Income taxes (received), net of refunds	$ 37	$ (103)	$ 36

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(In millions)	For the Years Ended December 31, 2015	2014	2013
STATEMENTS OF INCOME (LOSS)			
REVENUES:			
Electric sales to non-affiliates	$ 4,153	$ 5,114	$ 5,378
Electric sales to affiliates	664	861	652
Other	188	169	143
Total revenues*	5,005	6,144	6,173
OPERATING EXPENSES:			
Fuel	871	1,253	1,262
Purchased power from affiliates	353	271	486
Purchased power from non-affiliates	1,684	2,771	2,333
Other operating expenses	1,341	1,635	1,487
Pension and OPEB mark-to-market adjustment	57	297	(81)
Provision for depreciation	324	319	306
General taxes	98	128	138
Total operating expenses	4,728	6,674	5,931
OPERATING INCOME (LOSS)	277	(530)	242
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	—	(6)	(103)
Investment income (loss)	(14)	61	16
Miscellaneous income	3	6	28
Interest expense — affiliates	(7)	(7)	(10)
Interest expense — other	(147)	(146)	(160)
Capitalized interest	35	34	39
Total other expense	(130)	(58)	(190)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	147	(588)	52
INCOME TAXES (BENEFITS)	65	(228)	6
INCOME (LOSS) FROM CONTINUING OPERATIONS	82	(360)	46
Discontinued operations (net of income taxes of $70 and $8, respectively) (Note 19)	—	116	14
NET INCOME (LOSS)	$ 82	$ (244)	$ 60
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)			
NET INCOME (LOSS)	$ 82	$ (244)	$ 60
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(6)	(6)	(15)
Amortized gains on derivative hedges	(3)	(10)	(6)
Change in unrealized gain on available-for-sale securities	(9)	21	(8)
Other comprehensive income (loss)	(18)	5	(29)
Income taxes (benefits) on other comprehensive income (loss)	(7)	2	(11)
Other comprehensive income (loss), net of tax	(11)	3	(18)
COMPREHENSIVE INCOME (LOSS)	$ 71	$ (241)	$ 42

* Includes excise tax collections of $44 million, $69 million and $78 million in 2015, 2014 and 2013, respectively.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $8 in 2015 and $18 in 2014	275	415
Affiliated companies	451	525
Other, net of allowance for uncollectible accounts of $3 in 2015 and 2014	59	107
Notes receivable from affiliated companies	11	—
Materials and supplies	470	492
Derivatives	154	147
Collateral	70	229
Prepayments and other	66	68
	1,558	1,985
PROPERTY, PLANT AND EQUIPMENT:		
In service	14,311	13,596
Less — Accumulated provision for depreciation	5,765	5,208
	8,546	8,388
Construction work in progress	1,157	1,010
	9,703	9,398
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,327	1,365
Other	10	10
	1,337	1,375
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	61	78
Goodwill	23	23
Property taxes	40	41
Derivatives	79	52
Other	384	331
	587	525
	$ 13,185	$ 13,283
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 512	$ 506
Short-term borrowings-		
Affiliated companies	—	35
Other	8	99
Accounts payable-		
Affiliated companies	542	416
Other	139	248
Accrued taxes	76	102
Derivatives	104	166
Other	181	184
	1,562	1,756
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding as of December 31, 2015 and 2014	3,613	3,594
Accumulated other comprehensive income	46	57
Retained earnings	1,946	1,934
Total common stockholder's equity	5,605	5,585
Long-term debt and other long-term obligations	2,527	2,608
	8,132	8,193
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	791	824
Accumulated deferred income taxes	600	484
Retirement benefits	332	324
Asset retirement obligations	831	841
Derivatives	38	14
Other	899	847
	3,491	3,334
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)		
	$ 13,185	$ 13,283

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(In millions, except share amounts)	Common Stock		Accumulated Other Comprehensive Income	Retained Earnings
	Number of Shares	Carrying Value		
Balance, January 1, 2013	7	$ 1,573	$ 72	$ 2,118
Net income				60
Amortized loss on derivative hedges, net of $2 million of income tax benefits			(4)	
Change in unrealized gain on investments, net of $3 million of income tax benefits			(5)	
Pension and OPEB, net of $6 million of income tax benefits (Note 3)			(9)	
Equity contribution from parent		1,500		
Stock-based compensation		1		
Consolidated tax benefit allocation		6		
Balance, December 31, 2013	7	3,080	54	2,178
Net loss				(244)
Amortized loss on derivative hedges, net of $4 million of income tax benefits			(6)	
Change in unrealized gain on investments, net of $8 million of income taxes			13	
Pension and OPEB, net of $2 million of income tax benefits (Note 3)			(4)	
Equity contribution from parent		500		
Stock-based compensation		7		
Consolidated tax benefit allocation		7		
Balance, December 31, 2014	7	3,594	57	1,934
Net income				82
Amortized loss on derivative hedges, net of $1 million of income tax benefits			(2)	
Change in unrealized gain on investments, net of $4 million of income tax benefits			(5)	
Pension and OPEB, net of $2 million of income tax benefits (Note 3)			(4)	
Stock-based compensation		10		
Consolidated tax benefit allocation		9		
Cash dividends declared on common stock				(70)
Balance, December 31, 2015	7	$ 3,613	$ 46	$ 1,946

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(In millions)	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ 82	$ (244)	$ 60
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel and customer intangible amortization	569	599	533
Investment impairments	90	33	79
Pension and OPEB mark-to-market adjustment	57	297	(81)
Deferred income taxes and investment tax credits, net	119	7	309
Deferred costs on sale and leaseback transaction, net	48	48	48
Gain on investment securities held in trusts	(24)	(61)	(49)
Commodity derivative transactions, net (Note 10)	(74)	65	5
Loss on debt redemptions	—	6	103
Make-whole premiums paid on debt redemptions	—	—	(31)
Lease payments on sale and leaseback transaction	(131)	(131)	(131)
Income from discontinued operations (Note 19)	—	(116)	(14)
Change in current assets and liabilities-			
Receivables	277	674	(393)
Materials and supplies	(25)	(44)	57
Prepayments and other current assets	14	14	(39)
Accounts payable	(76)	(477)	(145)
Accrued taxes	(26)	(50)	(207)
Accrued compensation and benefits	(4)	(11)	2
Other current liabilities	47	(7)	15
Cash collateral, net	159	(92)	(34)
Other	49	61	(9)
Net cash provided from operating activities	1,151	571	78
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	341	878	—
Short-term borrowings, net	—	—	431
Equity contribution from parent	—	500	1,500
Redemptions and repayments-			
Long-term debt	(411)	(816)	(1,202)
Short-term borrowings, net	(126)	(301)	—
Tender premiums paid on debt redemptions	—	—	(67)
Common stock dividend payments	(70)	—	—
Other	(6)	(15)	(9)
Net cash (used for) provided from financing activities	(272)	246	653
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(627)	(839)	(717)
Nuclear fuel	(190)	(233)	(250)
Proceeds from asset sales	13	307	21
Sales of investment securities held in trusts	733	1,163	940
Purchases of investment securities held in trusts	(791)	(1,219)	(1,000)
Cash investments	(10)	—	—
Loans to affiliated companies, net	(11)	—	276
Other	4	4	(2)
Net cash used for investing activities	(879)	(817)	(732)
Net change in cash and cash equivalents	—	—	(1)
Cash and cash equivalents at beginning of period	2	2	3
Cash and cash equivalents at end of period	$ 2	$ 2	$ 2
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 114	$ 118	$ 157
Income taxes paid, net of refunds (received, net of payments)	$ (5)	$ (384)	$ 23

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FE's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy and its subsidiaries are involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 miles of lines and two regional transmission operation centers.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not necessarily indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation as appropriate. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 8, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, AGC, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.

FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets as of December 31, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets by Source	**December 31, 2015**	**December 31, 2014**	**Increase (Decrease)**
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within other noncurrent liabilities on the Consolidated Balance Sheets.

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements, and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, FirstEnergy accrues the estimated unbilled amount as revenue and reverses the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2015 and 2014 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2015 and 2014 are included below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2015		
Billed	$ 836	$ 165
Unbilled	579	110
Total	$ 1,415	$ 275
December 31, 2014		
Billed	$ 914	$ 239
Unbilled	640	176
Total	$ 1,554	$ 415

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2015	2014	2013
	(In millions, except per share amounts)		
Income from continuing operations available to common shareholders	$ 578	$ 213	$ 375
Discontinued operations (Note 19)	—	86	17
Net income	$ 578	$ 299	$ 392
Weighted average number of basic shares outstanding	422	420	418
Assumed exercise of dilutive stock options and awards[(1)]	2	1	1
Weighted average number of diluted shares outstanding	424	421	419
Earnings per share:			
Basic earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94
Diluted earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94

(1) For the years ended December 31, 2015, 2014 and 2013, approximately one million, two million, and two million shares were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within the CES segment's Property, plant and equipment and charged to fuel expense using the specific identification method. The cost of nuclear fuel included in CES' net plant as of December 31, 2015 was $418 million. Net plant in service balances by segment as of December 31, 2015 and 2014 were as follows:

	December 31, 2015			December 31, 2014		
Property, Plant and Equipment	**In Service[2]**	**Accum. Depr.**	**Net Plant**	**In Service[2]**	**Accum. Depr.**	**Net Plant**
			(In millions)			
Regulated Distribution	$ 24,553	$ (7,058)	$ 17,495	$ 23,973	$ (6,759)	$ 17,214
Regulated Transmission	7,703	(1,647)	6,056	6,634	(1,595)	5,039
Competitive Energy Services[1]	17,214	(6,213)	11,001	16,442	(5,598)	10,844
Corporate/Other	482	(242)	240	435	(198)	237
Total	$ 49,952	$ (15,160)	$ 34,792	$ 47,484	$ (14,150)	$ 33,334

[1] Primarily consists of generating assets and nuclear fuel as discussed above.
[2] Includes capital leases of $253 million and $281 million at December 31, 2015 and 2014, respectively.

The major classes of Property, plant and equipment are largely consistent with the segment disclosures above, with the exception of Regulated Distribution, which has approximately $2.0 billion of regulated generation net plant in service.

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's and FES' electric plant in 2015, 2014 and 2013 are shown in the following table:

	Annual Composite Depreciation Rate		
	2015	**2014**	**2013**
FirstEnergy	2.5%	2.5%	2.6%
FES	3.2%	3.1%	3.1%

For the years ended December 31, 2015, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $49 million, $49 million and $28 million, respectively, of allowance for equity funds used during construction and $68 million, $69 million and $75 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,003 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, plant and equipment includes $666 million representing AGC's share in this facility as of December 31, 2015 of which $484 million is unregulated and included within the CES segment. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statements of Income.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value.

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. In connection with the transaction, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The impairment charge recognized in 2013 is included within the results of the Regulated Distribution segment.

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the Hatfield's Ferry, generating Units 1-3, and Mitchell, generating units 2-3. As a result of this decision FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge recognized in 2013 is included within the results of the CES segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

During 2015, FirstEnergy recognized impairments totaling $42 million associated with certain non-core assets, including equipment and facilities. The impairment charges are included within the Regulated Distribution segment ($8 million) and the CES segment ($34 million).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents goodwill by reporting unit:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
	(In millions)			
Balance as of December 31, 2015	$ 5,092	$ 526	$ 800	$ 6,418

There were no changes in goodwill for any reporting unit during 2015. As of December 31, 2015 and 2014, total goodwill recognized by FES was $23 million. Neither FirstEnergy nor FES has accumulated impairment charges as of December 31, 2015.

Annual impairment testing is conducted as of July 31 of each year and for 2015, 2014 and 2013, the analysis indicated no impairment of goodwill. For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.

- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital and revised environmental requirements could have a negative impact on future goodwill assessments.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets. In 2015, 2014 and 2013, FirstEnergy recognized $102 million, $37 million and $90 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $90 million, $33 million and $79 million, respectively. The fair values of FirstEnergy's investments are disclosed in Note 9, Fair Value Measurements.

FirstEnergy holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. In 2015, Global Holding incurred losses primarily as a result of declines in coal prices due to weakening global and U.S. coal demand. Based on the significant decline in coal pricing and the current outlook for the coal market, including the significant decline in the market capitalization of coal companies in 2015, FirstEnergy assessed the value of its investment in Global Holding and determined there was a decline in the fair value of the investment below its carrying value that was other than temporary, resulting in an a pre-tax impairment charge of $362 million. Key assumptions incorporated into the discounted cash flow analysis utilized in the impairment analysis included the discount rate, future long term coal prices, production levels, sales forecasts, projected capital and operating costs. The impairment charge is classified as a component of Other Income (Expense) in the Consolidated Statement of Income. See Note 8, Variable Interest Entities, for further discussion of FirstEnergy's investment in Global Holding.

INVENTORY

Materials and supplies inventory includes fuel inventory and the distribution, transmission and generation plant materials, net of reserve for excess and obsolete inventory. Materials are generally charged to inventory at weighted average cost when purchased and expensed or capitalized, as appropriate, when used or installed. Fuel inventory is accounted for at weighted average cost when purchased, and recorded to fuel expense when consumed.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FirstEnergy are shown in the following table:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ (38)	$ 15	$ 408	$ 385
Other comprehensive income before reclassifications	—	46	35	81
Amounts reclassified from AOCI	3	(56)	(195)	(248)
Other comprehensive income (loss)	3	(10)	(160)	(167)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(63)	(66)
Other comprehensive income (loss), net of tax	2	(6)	(97)	(101)
AOCI Balance, December 31, 2013	$ (36)	$ 9	$ 311	$ 284
Other comprehensive income before reclassifications	—	89	92	181
Amounts reclassified from AOCI	(2)	(63)	(168)	(233)
Other comprehensive income (loss)	(2)	26	(76)	(52)
Income tax (benefits) on other comprehensive income (loss)	(1)	10	(23)	(14)
Other comprehensive income (loss), net of tax	(1)	16	(53)	(38)
AOCI Balance, December 31, 2014	$ (37)	$ 25	$ 258	$ 246
Other comprehensive income before reclassifications	—	14	10	24
Amounts reclassified from AOCI	5	(25)	(126)	(146)
Other comprehensive income (loss)	5	(11)	(116)	(122)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(44)	(47)
Other comprehensive income (loss), net of tax	4	(7)	(72)	(75)
AOCI Balance, December 31, 2015	$ (33)	$ 18	$ 186	$ 171

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2015, 2014 and 2013:

FirstEnergy

Reclassifications from AOCI [2]	Year Ended December 31, 2015	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	8	8	11	Interest expense
	5	(2)	3	Total before taxes
	(1)	1	(1)	Income taxes (benefits)
	$ 4	$ (1)	$ 2	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (25)	$ (63)	$ (56)	Investment income (loss)
	9	24	21	Income taxes (benefits)
	$ (16)	$ (39)	$ (35)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (126)	$ (168)	$ (195)	[1]
	49	65	75	Income taxes (benefits)
	$ (77)	$ (103)	$ (120)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FES are shown in the following table:

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ 3	$ 13	$ 56	$ 72
Other comprehensive income before reclassifications	—	41	5	46
Amounts reclassified from AOCI	(6)	(49)	(20)	(75)
Other comprehensive loss	(6)	(8)	(15)	(29)
Income tax benefits on other comprehensive loss	(2)	(3)	(6)	(11)
Other comprehensive loss, net of tax	(4)	(5)	(9)	(18)
AOCI Balance, December 31, 2013	$ (1)	$ 8	$ 47	$ 54
Other comprehensive income before reclassifications	—	80	13	93
Amounts reclassified from AOCI	(10)	(59)	(19)	(88)
Other comprehensive income (loss)	(10)	21	(6)	5
Income tax (benefits) on other comprehensive income (loss)	(4)	8	(2)	2
Other comprehensive income (loss), net of tax	(6)	13	(4)	3
AOCI Balance, December 31, 2014	$ (7)	$ 21	$ 43	$ 57
Other comprehensive income before reclassifications	—	15	10	25
Amounts reclassified from AOCI	(3)	(24)	(16)	(43)
Other comprehensive loss	(3)	(9)	(6)	(18)
Income tax benefits on other comprehensive loss	(1)	(4)	(2)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(4)	(11)
AOCI Balance, December 31, 2015	$ (9)	$ 16	$ 39	$ 46

The following amounts were reclassified from AOCI for FES in the years ended December 31, 2015, 2014 and 2013:

FES

Reclassifications from AOCI [2]	Year Ended December 31, 2015	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	—	—	2	Interest expense - other
	(3)	(10)	(6)	Total before taxes
	1	4	2	Income taxes (benefits)
	$ (2)	$ (6)	$ (4)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (24)	$ (59)	$ (49)	Investment income (loss)
	9	22	18	Income taxes (benefits)
	$ (15)	$ (37)	$ (31)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (16)	$ (19)	$ (20)	[1]
	6	7	8	Income taxes (benefits)
	$ (10)	$ (12)	$ (12)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. In 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Payment of benefits for participants that elected an immediate lump sum cash payment or an annuity resulted in a $40 million reduction to the underfunded status of the pension plan. Additionally, during 2015 and 2014, certain unions ratified their labor agreements that ended subsidized retiree health care resulting in a reduction to the OPEB benefit obligation by approximately $10 million and $97 million, respectively.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively. In 2015, the pension and OPEB mark-to-market adjustment primarily reflects lower than expected asset returns as well as the impact of other demographic assumptions, including revisions to mortality assumptions, partially offset by a 25 basis point increase in the discount rate.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. In 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million, or (2.7)% compared to earnings of $387 million, or 6.2% in 2014 and losses of $(22) million, or (0.3)% in 2013, and assumed a 7.75% rate of return for each year on plan assets which generated $476 million, $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of $49 million and $1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Obligations and Funded Status	Pension 2015	Pension 2014	OPEB 2015	OPEB 2014
	(In millions)			
Change in benefit obligation:				
Benefit obligation as of January 1	$ 9,249	$ 8,263	$ 757	$ 879
Service cost	193	167	5	9
Interest cost	383	402	29	39
Plan participants' contributions	—	—	6	16
Plan amendments	—	5	(10)	(97)
Medicare retiree drug subsidy	—	—	1	—
Actuarial (gain) loss	(277)	1,123	(2)	13
Benefits paid	(469)	(711)	(62)	(102)
Benefit obligation as of December 31	$ 9,079	$ 9,249	$ 724	$ 757
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 5,824	$ 6,171	$ 464	$ 495
Actual return (losses) on plan assets	(178)	349	6	38
Company contributions	161	15	17	17
Plan participants' contributions	—	—	6	16
Benefits paid	(469)	(711)	(62)	(102)
Fair value of plan assets as of December 31	$ 5,338	$ 5,824	$ 431	$ 464
Funded Status:				
Qualified plan	$ (3,366)	$ (3,064)		
Non-qualified plans	(375)	(361)		
Funded Status	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Accumulated benefit obligation	$ 8,579	$ 8,744	$ —	$ —
Amounts Recognized on the Balance Sheet:				
Current liabilities	$ (18)	$ (17)	$ —	$ —
Noncurrent liabilities	(3,723)	(3,408)	(293)	(293)
Net liability as of December 31	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 37	$ 45	$ (355)	$ (479)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	4.50%	4.25%	4.25%	4.00%
Rate of compensation increase	4.20%	4.20%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	7.5-7.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2026	2026
Allocation of Plan Assets (as of December 31)				
Equity securities	40%	36%	51%	49%
Bonds	34%	33%	43%	40%
Absolute return strategies	7%	14%	—%	1%
Real estate	11%	7%	—%	1%
Derivatives	—%	1%	—%	—%
Cash and short-term securities	8%	9%	6%	9%
Total	100%	100%	100%	100%

The estimated 2016 amortization of pension and OPEB prior service costs (credits) from AOCI into net periodic pension and OPEB costs (credits) is approximately $8 million and $(80) million, respectively.

Components of Net Periodic Benefit Costs	Pension 2015	Pension 2014	Pension 2013	OPEB 2015	OPEB 2014	OPEB 2013
			(In millions)			
Service cost	$ 193	$ 167	$ 197	$ 5	$ 9	$ 13
Interest cost	383	402	372	29	39	37
Expected return on plan assets	(443)	(462)	(501)	(33)	(34)	(34)
Amortization of prior service cost (credit)	8	8	12	(134)	(176)	(207)
Pension & OPEB mark-to-market adjustment	344	1,235	(267)	25	8	(129)
Net periodic cost (credit)	$ 485	$ 1,350	$ (187)	$ (108)	$ (154)	$ (320)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension 2015	Pension 2014	Pension 2013	OPEB 2015	OPEB 2014	OPEB 2013
Weighted-average discount rate	4.25%	5.00%	4.25%	4.00%	4.75%	4.00%
Expected long-term return on plan assets	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Rate of compensation increase	4.20%	4.20%	4.70%	N/A	N/A	N/A

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed rates of return on plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy. In 2016, FirstEnergy decreased the expected long-term return on plan assets to 7.50%.

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 9, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2015 and 2014.

	December 31, 2015				
	Level 1	Level 2	Level 3	Total	Asset Allocation
		(In millions)			
Cash and short-term securities	$ —	$ 427	$ —	$ 427	8%
Equity investments					
Domestic	869	75	—	944	18%
International	395	794	—	1,189	22%
Fixed income					
Government bonds	—	232	—	232	4%
Corporate bonds	—	1,115	—	1,115	21%
High yield debt	—	438	—	438	8%
Mortgage-backed securities (non-government)	—	31	—	31	1%
Alternatives					
Hedge funds (Absolute return)	—	343	—	343	7%
Derivatives	—	15	—	15	—%
Private equity funds	—	—	24	24	—%
Real estate funds	—	—	587	587	11%
Total (1)	$ 1,264	$ 3,470	$ 611	$ 5,345	100%

(1) Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$ —	$ 517	$ —	$ 517	9%
Equity investments					
Domestic	1,266	8	—	1,274	22%
International	355	414	—	769	14%
Fixed income					
Government bonds	—	159	—	159	3%
Corporate bonds	—	1,386	—	1,386	24%
High yield debt	—	300	—	300	5%
Mortgage-backed securities (non-government)	—	37	—	37	1%
Alternatives					
Hedge funds (Absolute return)	—	809	—	809	14%
Derivatives	—	35	—	35	1%
Private equity funds	—	—	25	25	—%
Real estate funds	—	—	421	421	7%
Total [1]	$ 1,621	$ 3,665	$ 446	$ 5,732	100%

[1] Excludes $92 million as of December 31, 2014 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2015 and 2014:

	Private Equity Funds	Real Estate Funds
	(In millions)	
Balance as of January 1, 2014	$ 27	$ 385
Actual return on plan assets:		
Unrealized gains (losses)	(2)	17
Realized gains	1	14
Transfers in (out)	(1)	5
Balance as of December 31, 2014	$ 25	$ 421
Actual return on plan assets:		
Unrealized gains	—	42
Realized gains (losses)	(1)	16
Transfers in	—	108
Balance as of December 31, 2015	$ 24	$ 587

As of December 31, 2015 and 2014, the OPEB trust investments measured at fair value were as follows:

	December 31, 2015				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$ —	$ 25	$ —	$ 25	6%
Equity investment					
Domestic	219	—	—	219	50%
International	1	3	—	4	1%
Fixed income					
U.S. treasuries	—	42	—	42	10%
Government bonds	—	114	—	114	26%
Corporate bonds	—	27	—	27	6%
High yield debt	—	1	—	1	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	1	—	1	—%
Real estate funds	—	—	2	2	—%
Total [(1)]	$ 220	$ 216	$ 2	$ 438	100%

(1) Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$ —	$ 41	$ —	$ 41	9%
Equity investment					
Domestic	230	—	—	230	48%
International	3	3	—	6	1%
Fixed income					
U.S. treasuries	—	41	—	41	9%
Government bonds	—	110	—	110	23%
Corporate bonds	—	32	—	32	7%
High yield debt	—	2	—	2	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	5	—	5	1%
Real estate funds	—	—	3	3	1%
Total [(1)]	$ 233	$ 237	$ 3	$ 473	100%

(1) Excludes $(9) million as of December 31, 2014, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2015 and 2014:

	Real Estate Funds
Balance as of January 1, 2014	$ 5
Transfers out	(2)
Balance as of December 31, 2014	$ 3
Transfers out	(1)
Balance as of December 31, 2015	$ 2

FirstEnergy follows a total return investment approach using a mix of equities, fixed income and other available investments while taking into account the pension plan liabilities to optimize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

FirstEnergy's target asset allocations for its pension and OPEB trust portfolios for 2015 and 2014 are shown in the following table:

Target Asset Allocations	2015	2014
Equities	38%	42%
Fixed income	30%	32%
Absolute return strategies	8%	14%
Real estate	10%	5%
Alternative investments	8%	1%
Cash	6%	6%
	100%	100%

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 1	$ (1)
Effect on accumulated benefit obligation	$ 26	$ (23)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets and other payments, net of participant contributions:

		OPEB	
	Pension	Benefit Payments	Subsidy Receipts
		(In millions)	
2016	$ 484	$ 54	$ (3)
2017	505	54	(3)
2018	522	54	(3)
2019	533	54	(3)
2020	551	54	(3)
Years 2021-2025	2,946	259	(9)

FES' share of the pension and OPEB net (liability) asset as of December 31, 2015 and 2014, was as follows:

	Pension		OPEB	
	2015	2014	2015	2014
	(In millions)			
Net (Liability) Asset	$ (303)	$ (295)	$ 25	$ 10

FES' share of the net periodic benefit cost (credit), including the pension and OPEB mark-to-market adjustment, for the three years ended December 31, 2015 was as follows:

	Pension			OPEB		
	2015	2014	2013	2015	2014	2013
	(In millions)					
Net Periodic Cost (Credit)	$ 10	$ 150	$ (30)	$ (22)	$ (24)	$ (40)

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2015, approximately 9.9 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Any shares not issued due to forfeitures or cancellations are added back to the ICP 2015. Shares used under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date, less estimated forfeitures. FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Realized tax benefits during the years ended December 31, 2015, 2014 and 2013 were $10 million, $13 million and $13 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as a financing activity on the Consolidated Statements of Cash Flows.

Stock-based compensation costs and the amount of stock-based compensation expense capitalized related to FirstEnergy and FES plans are included in the following tables:

FirstEnergy	Years ended December 31,		
Stock-based Compensation Plan	**2015**	**2014**	**2013**
	(In millions)		
Restricted Stock Units	$ 46	$ 26	$ 36
Restricted Stock	2	5	6
Performance Shares	—	5	(10)
401(k) Savings Plan	38	25	25
EDCP & DCPD	3	8	3
Total	$ 89	$ 69	$ 60
Stock-based compensation costs capitalized	$ 32	$ 23	$ 20

FES Stock-based Compensation Plan	Years ended December 31, 2015	2014	2013
		(In millions)	
Restricted Stock Units	$ 6	$ 4	$ 6
Performance Shares	—	1	(1)
401(k) Savings Plan	5	4	4
Total	$ 11	$ 9	$ 9
Stock-based compensation costs capitalized	$ 1	$ 1	$ 1

Stock option expense was not material for FirstEnergy or FES for the years December 31, 2015, 2014 or 2013. Income tax benefits associated with stock based compensation plan expense were $12 million, $14 million and $23 million (FES - $2 million, $2 million and $1 million) for the years ended 2015, 2014 and 2013, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds will be paid in stock and one-third will be paid in cash. Prior to 2015, all performance-based restricted stock units were paid in stock. Restricted stock units paid in stock provide the participant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Compensation expense is recognized for the grant date fair value of awards that are expected to vest. Restricted stock units paid in cash provide the participant the right to receive cash based on the numbers of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date. The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for cash performance based restricted stock units as of December 31, 2015 was $3 million. No cash was paid to settle the restricted stock unit obligations in 2015. The vesting period for each of the awards was three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions.

Restricted stock unit activity for the year ended December 31, 2015, was as follows:

Restricted Stock Unit Activity	Shares	Weighted-Average Grant Date Fair Value
Nonvested as of January 1, 2015	2,069,518	$ 37.65
Granted in 2015	1,157,755	35.27
Forfeited in 2015	(231,271)	34.19
Vested in 2015[1]	(559,114)	44.58
Nonvested as of December 31, 2015	2,436,888	$ 35.26

[1] Excludes dividend equivalents of 89,681 earned during vesting period

The weighted average fair value of awards granted in 2015, 2014 and 2013 were $35.27, $32.17 and $39.90 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock units vested was $22 million, $28 million, and $37 million, respectively. As of December 31, 2015, there was $32 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock units; that cost is expected to be recognized over a period of approximately two years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FirstEnergy common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock.

Restricted common stock (restricted stock) activity for the year ended December 31, 2015, was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2015	342,286	$ 45.29
Granted in 2015	65,434	32.98
Forfeited in 2015	(26,079)	57.58
Vested in 2015[1]	(190,985)	43.17
Nonvested as of December 31, 2015	190,656	$ 40.65

(1) Excludes 52,872 shares for dividends earned during vesting period

The weighted average vesting period for restricted stock granted in 2015 was 5.59 years. The weighted average fair value of awards granted in 2015, 2014, and 2013 were $32.98, $32.71 and $42.53 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock vested was $8 million, $4 million, and $7 million, respectively. As of December 31, 2015, there was $3 million of total unrecognized compensation cost related to non-vested restricted stock, which is expected to be recognized over a period of approximately three years.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2015. Stock option activity during 2015 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2015 (1,077,988 options exercisable)	1,439,145	$ 44.83
Options exercised	(18,551)	29.53
Options forfeited	(8,623)	68.02
Balance, December 31, 2015 (1,211,358 options exercisable)	1,411,971	$ 44.89

Cash received from the exercise of stock options in 2015, 2014 and 2013 was $1 million, $1 million and $19 million, respectively. The total intrinsic value of options exercised during 2015 was not material. The weighted-average remaining contractual term of options outstanding as of December 31, 2015 was 3.58 years.

Performance Shares

Prior to the 2015 grant of performance-based restricted stock units discussed above, the Company granted performance shares. Performance shares are share equivalents and do not have voting rights. The performance shares outstanding track the performance of FE's common stock over a three-year vesting period. Dividend equivalents accrue on performance shares and are reinvested into additional performance shares with the same performance conditions. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. No performance shares were granted in 2015. In 2014, $3 million cash was paid to settle performance share obligations. During 2015 and 2013, no cash was paid to settle performance shares due to the performance criteria not being met for the previous three-year vesting period.

401(k) Savings Plan

In 2015 and 2014, 1,072,494 and 756,412 shares of FE common stock, respectively, were issued and contributed to participants' accounts. In 2013, approximately 708,000 shares of FE common stock were purchased on the market and contributed to participants' accounts.

EDCP

Under the EDCP, covered employees can defer a portion of their compensation, including base salary, annual incentive awards and/or long-term incentive awards, into unfunded accounts. Annual incentive and long-term incentive awards may be deferred in FE stock accounts. Base salary and annual incentive awards may be deferred into a retirement cash account which earns interest. Dividends are calculated quarterly on stock units outstanding and are credited in the form of additional stock units. The form of payout as stock or cash can vary depending upon the form of the award, the duration of the deferral and other factors. Certain types of deferrals such as dividend equivalent units, Short-Term Incentive Awards, and performance share awards are required to be paid in cash. Until 2015, payouts of the stock accounts typically occurred three years from the date of deferral, although participants could have elected to defer their shares into a retirement stock account that would pay out in cash upon retirement. In 2015, FirstEnergy amended the EDCP to eliminate the right to receive deferred shares after three years, effective for deferrals made on or after November 1, 2015. Awards deferred into a retirement stock account will pay out in cash upon separation from service, death or disability. Interest accrues on the cash allocated to the retirement cash account and the balance will pay out in cash over a time period as elected by the participant.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $9 million and $8 million as of December 31, 2015 and December 31, 2014, respectively, is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

5. TAXES

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

On December 18, 2015, the President signed into law the Protecting Americans from Tax Hikes Act of 2015 (the Act). The Act, among other things, made permanent the R&D tax credit, and also extended accelerated depreciation of qualified capital investments placed into service. This bonus depreciation provision is 50% for qualifying assets placed into service from 2015 through 2017, 40% for qualifying assets placed into service in 2018 and 30% for qualifying assets placed into service in 2019. FirstEnergy and FES recorded the effects of the Act that apply to 2015 in the fourth quarter of 2015. The extension of the tax benefits did not have a significant impact to the effective tax rate.

INCOME TAXES (BENEFITS)[1]	2015	2014	2013
		(In millions)	
FirstEnergy			
Currently payable (receivable)-			
Federal	$ 1	$ (132)	$ (118)
State	30	(72)	70
	31	(204)	(48)
Deferred, net-			
Federal	277	214	305
State	15	(42)	(54)
	292	172	251
Investment tax credit amortization	(8)	(10)	(8)
Total provision for income taxes (benefits)	$ 315	$ (42)	$ 195
FES			
Currently payable (receivable)-			
Federal	$ (56)	$ (222)	$ (300)
State	2	(13)	(3)
	(54)	(235)	(303)
Deferred, net-			
Federal	103	25	317
State	18	(14)	(4)
	121	11	313
Investment tax credit amortization	(2)	(4)	(4)
Total provision for income taxes (benefits)	$ 65	$ (228)	$ 6

[1]Provision for Income Taxes (Benefits) on Income from Continuing Operations. Currently payable (receivable) in 2014 excludes $106 million and $12 million of federal and state taxes, respectively, associated with discontinued operations. Deferred, net in 2014 excludes $44 million and $5 million of federal and state tax benefits, respectively, associated with discontinued operations.

FirstEnergy and FES tax rates are affected by permanent items, such as AFUDC equity and other flow-through items as well as discrete items that may occur in any given period, but are not consistent from period to period. The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total income taxes on continuing operations for the three years ended December 31:

	2015	2014	2013
		(In millions)	
FirstEnergy			
Income from Continuing Operations before income taxes	$ 893	$ 171	$ 570
Federal income tax expense at statutory rate (35%)	$ 313	$ 60	$ 199
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	34	12	10
AFUDC equity and other flow-through	(16)	(13)	(7)
Amortization of investment tax credits	(8)	(10)	(8)
Change in accounting method	(8)	(27)	—
ESOP dividend	(6)	(6)	(9)
Tax basis balance sheet adjustments	—	(25)	—
Uncertain tax positions	1	(35)	(2)
Other, net	5	2	12
Total income taxes (benefits)	$ 315	$ (42)	$ 195
Effective income tax rate	35.3%	(24.6)%	34.2%
FES			
Income (loss) from Continuing Operations before income taxes (benefits)	$ 147	$ (588)	$ 52
Federal income tax expense (benefit) at statutory rate (35%)	$ 51	$ (206)	$ 18
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	16	(14)	(5)
Amortization of investment tax credits	(2)	(4)	(4)
ESOP dividend	(1)	(1)	(2)
Uncertain tax positions	5	—	—
Other, net	(4)	(3)	(1)
Total income taxes (benefits)	$ 65	$ (228)	$ 6
Effective income tax rate	44.2%	38.8 %	11.5%

In 2015, FirstEnergy's effective tax rate was 35.3% compared to (24.6)% in 2014. The increase in the effective tax rate year-over-year resulted from lower tax benefits in 2015 as compared to 2014, primarily related to IRS approved changes in accounting methods, reduced tax benefits on uncertain tax positions, partially offset by lower valuation allowances required on state and municipal net operating loss carryforwards that FirstEnergy believes are no longer realizable. Additionally, during 2014, income tax benefits of $25 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the FirstEnergy's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period. The increase in the effective rate was also impacted by higher income from continuing operations.

In 2015, FES' effective tax rate on income from continuing operations was 44.2% compared to 38.8% on a loss from continuing operations in 2014. The increase in the effective tax rate is primarily due to an increase in reserves associated with uncertain tax positions in 2015 and the absence of tax benefits recognized in 2014 associated with changes in state apportionment factors, partially offset by lower valuation allowances recorded on state and municipal NOL carryforwards that FirstEnergy believes are no longer realizable.

Accumulated deferred income taxes as of December 31, 2015 and 2014 are as follows:

	2015	2014
	(In millions)	
FirstEnergy		
Property basis differences	$ 9,920	$ 9,354
Deferred sale and leaseback gain	(360)	(381)
Pension and OPEB	(1,541)	(1,433)
Nuclear decommissioning activities	480	458
Asset retirement obligations	(731)	(641)
Regulatory asset/liability	763	768
Loss carryforwards and AMT credits	(1,965)	(1,932)
Loss carryforward valuation reserve	192	174
All other	15	172
Net deferred income tax liability	$ 6,773	$ 6,539
FES		
Property basis differences	$ 1,901	$ 1,749
Deferred sale and leaseback gain	(342)	(356)
Pension and OPEB	(393)	(373)
Lease market valuation liability	95	75
Nuclear decommissioning activities	483	489
Asset retirement obligations	(509)	(486)
Loss carryforwards and AMT credits	(687)	(631)
Loss carryforward valuation reserve	46	32
All other	6	(15)
Net deferred income tax liability	$ 600	$ 484

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2011-2014. In January 2015, the IRS completed its examination of the 2013 federal income tax return and issued a Revenue Agent Report and there were no material impacts to FirstEnergy's effective tax rate associated with this examination. Tax year 2014 is currently under review by the IRS.

FirstEnergy has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2015, the deferred income tax assets, before any valuation allowances, for loss carryforwards and AMT credits consisted of $1.5 billion of Federal NOL carryforwards, net of tax, that will begin to expire in 2030, Federal AMT credits of $26 million, net of tax, that have an indefinite carryforward period, and $398 million, net of tax, of state and local NOL carryforwards that will begin to expire in 2016.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $10 billion for FirstEnergy, of which approximately $6 billion is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	**FirstEnergy**		**FES**	
	(In millions)			
	State	**Local**	**State**	**Local**
2016-2020	$ 403	$ 2,983	$ 95	$ 1,820
2021-2025	1,323	—	68	—
2026-2030	2,205	—	259	—
2031-2035	3,245	—	1,128	—
	$ 7,176	$ 2,983	$ 1,550	$ 1,820

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute is utilized for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2015 and 2014, FirstEnergy's total unrecognized income tax benefits were approximately $34 million.

If ultimately recognized in future years, approximately $29 million of unrecognized income tax benefits as of December 31, 2015, would impact the effective tax rate. As of December 31, 2015, it is reasonably possible that approximately $9 million of unrecognized tax benefits may be resolved during 2016 as a result of the statute of limitations expiring, of which approximately $7 million would affect FirstEnergy's effective tax rate.

The following table summarizes the changes in unrecognized tax positions for the years ended 2015, 2014 and 2013:

	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2013	$ 43	$ 3
Prior years increases	10	—
Prior years decreases	(5)	—
Balance, December 31, 2013	$ 48	$ 3
Current year increases	4	—
Prior years increases	5	—
Prior years decreases	(23)	—
Balance, December 31, 2014	$ 34	$ 3
Current year increases	3	—
Prior years increases	7	5
Prior years decreases	(10)	—
Balance, December 31, 2015	$ 34	$ 8

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy's reversal of accrued interest associated with unrecognized tax benefits reduced FirstEnergy's effective tax rate in 2015 and 2014 by approximately $1 million and $6 million, respectively. There was an increase of $1 million of accrued interest for the year ended December 31, 2013.

The following table summarizes the net interest expense (income) for the three years ended December 31, 2015 and the cumulative net interest payable as of December 31, 2015 and 2014 (FES did not have net interest expense (income) or a net interest payable for the periods presented):

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2015	**2014**	**2013**	**2015**	**2014**
		(In millions)		*(In millions)*	
FirstEnergy	$ (1)	$ (6)	$ 1	$ 1	$ 2

General Taxes

	2015	2014	2013
		(In millions)	
FirstEnergy			
KWH excise	$ 193	$ 194	$ 219
State gross receipts	224	226	240
Real and personal property	410	393	368
Social security and unemployment	119	112	110
Other	32	37	41
Total general taxes	$ 978	$ 962	$ 978
FES			
State gross receipts	$ 44	$ 69	$ 77
Real and personal property	36	39	40
Social security and unemployment	16	17	19
Other	2	3	2
Total general taxes	$ 98	$ 128	$ 138

6. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years, expiring in 2016. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years expiring in 2017. OE, CEI and TE have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years, expiring in 2040. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. In 2013, FG acquired the remaining lessor interests in Bruce Mansfield Units 1, 2 and 3, which were part of the leases entered into by CEI and TE in 1987.

In February 2014, NG purchased 47.7 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. In November 2014, NG repurchased 55.3 MW of lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. OE and TE continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. During 2013, the investments held at Shippingport were liquidated. The PNBV arrangements effectively reduce lease costs related to those transactions (see Note 8, Variable Interest Entities).

As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

Operating lease expense for 2015, 2014 and 2013, is summarized as follows:

(In millions)	2015	2014	2013
FirstEnergy	$ 174	$ 199	$ 224
FES	$ 94	$ 95	$ 97

The future minimum capital lease payments as of December 31, 2015 are as follows:

Capital leases	FirstEnergy	FES
	(In millions)	
2016	$ 36	$ 6
2017	31	6
2018	24	2
2019	18	—
2020	14	—
Years thereafter	27	—
Total minimum lease payments	150	14
Interest portion	(18)	(1)
Present value of net minimum lease payments	132	13
Less current portion	32	5
Noncurrent portion	$ 100	$ 8

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2015, are as follows:

Operating Leases	FirstEnergy Lease Payments	PNBV	Net
		(In millions)	
2016	$ 197	$ 13	$ 184
2017	122	3	119
2018	135	—	135
2019	116	—	116
2020	91	—	91
Years thereafter	1,438	—	1,438
Total minimum lease payments	$ 2,099	$ 16	$ 2,083

FES' future minimum operating lease payments as of December 31, 2015, are as follows:

Operating Leases	Lease Payments
	(In millions)
2016	$ 131
2017	82
2018	101
2019	97
2020	68
Years thereafter	1,315
Total minimum lease payments	$ 1,794

7. INTANGIBLE ASSETS

As of December 31, 2015, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

	Intangible Assets			Amortization Expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2015	2016	2017	2018	2019	2020	Thereafter
NUG contracts[1]	$ 124	$ 25	$ 99	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 74
OVEC	54	9	45	2	2	2	2	2	2	35
Coal contracts[2][3][4]	556	430	126	116	38	32	17	17	6	—
FES customer contracts	148	87	61	17	17	16	14	13	1	—
	$ 882	$ 551	$ 331	$ 140	$ 62	$ 55	$ 38	$ 37	$ 14	$ 109

(1) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.
(2) A gross amount of $40 million ($23 million, net) of the coal contracts is related to FES. The 2015 and estimated 2016 to 2019 amortization expense for FES is $5.7 million annually.
(3) A gross amount of $102 million ($16 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings. Accordingly, the amortization expense for these coal contracts is excluded from table above.
(4) Amortization expense in 2015, includes a $67 million impairment of a coal contract intangible asset associated with the termination of a coal supply contract, which impacted earnings.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

8. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has (i) the power to direct the activities of a VIE that most significantly impact the entity's economic performance, and (ii) 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. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into categories based on similar risk characteristics and significance.

Consolidated VIEs

VIEs in which FirstEnergy is the primary beneficiary consist of the following (included in FirstEnergy's consolidated financial statements):

- ***PNBV*** - PNBV, a business trust established by OE in 1996, issued certain beneficial interests and notes to fund the acquisition of a portion of the bonds issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. The beneficial ownership of PNBV includes a 3% interest by unaffiliated third parties.
- ***Ohio Securitization*** - In September 2012, the Ohio Companies created separate, wholly-owned limited liability companies (SPEs) which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. As of December 31, 2015 and December 31, 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.
- ***JCP&L Securitization*** - In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of December 31, 2015 and December 31, 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.
- ***MP and PE Environmental Funding Companies*** - The entities issued bonds of which the proceeds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2015 and December 31, 2014, $429 million and $450 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- ***Global Holding*** - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting. See Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

  As discussed in Note 15, Commitments, Guarantees and Contingencies, FE is the guarantor under Global Holding's $300 million term loan facility. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- ***PATH WV*** - PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.
- ***Power Purchase Agreements*** - FirstEnergy evaluated its power purchase agreements and determined that certain NUG

entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production.

FirstEnergy maintains 15 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $116 million and $185 million, respectively, during the years ended December 31, 2015 and 2014.

- ***Sale and Leaseback Transactions*** - FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. Upon the completion of these transactions, NG will have obtained all of the lessor equity interests at Perry Unit 1 and Beaver Valley Unit 2.

FES and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of December 31, 2015:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
		(In millions)	
FirstEnergy	$ 1,225	$ 950	$ 275
FES	$ 1,155	$ 933	$ 222

9. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation processes for FTRs and NUGs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 10, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWHs. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWHs reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWHs. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2015, from those used as of December 31, 2014. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2015 and 2014. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	**December 31, 2015**				**December 31, 2014**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 1,245	$ —	$ 1,245	$ —	$ 1,221	$ —	$ 1,221
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	8	8	—	—	39	39
Derivative assets - NUG contracts(1)	—	—	1	1	—	—	2	2
Equity securities(2)	576	—	—	576	592	—	—	592
Foreign government debt securities	—	75	—	75	—	76	—	76
U.S. government debt securities	—	180	—	180	—	182	—	182
U.S. state debt securities	—	246	—	246	—	237	—	237
Other(3)	105	212	—	317	55	256	—	311
Total assets	$ 685	$ 2,182	$ 9	$ 2,876	$ 648	$ 2,143	$ 41	$ 2,832
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(13)	(13)	—	—	(14)	(14)
Derivative liabilities - NUG contracts(1)	—	—	(137)	(137)	—	—	(153)	(153)
Total liabilities	$ (9)	$ (122)	$ (150)	$ (281)	$ (26)	$ (141)	$ (167)	$ (334)
Net assets (liabilities)(4)	$ 676	$ 2,060	$ (141)	$ 2,595	$ 622	$ 2,002	$ (126)	$ 2,498

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(3) Primarily consists of cash and short-term cash investments.
(4) Excludes $7 million and $40 million as of December 31, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2015 and December 31, 2014:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
			(In millions)			
January 1, 2014 Balance	$ 20	$ (222)	$ (202)	$ 4	$ (12)	$ (8)
Unrealized gain (loss)	2	(2)	—	47	(1)	46
Purchases	—	—	—	26	(16)	10
Settlements	(20)	71	51	(38)	15	(23)
December 31, 2014 Balance	$ 2	$ (153)	$ (151)	$ 39	$ (14)	$ 25
Unrealized gain (loss)	2	(49)	(47)	(5)	(7)	(12)
Purchases	—	—	—	22	(11)	11
Settlements	(3)	65	62	(48)	19	(29)
December 31, 2015 Balance	$ 1	$ (137)	$ (136)	$ 8	$ (13)	$ (5)

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (5)	Model	RTO auction clearing prices	($3.90) to $6.90	$1.00	Dollars/MWH
NUG Contracts	$ (136)	Model	Generation	400 to 3,871,000	839,000	MWH
			Regional electricity prices	$38.10 to $45.60	$40.20	Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				(In millions)				
Corporate debt securities	$ —	$ 678	$ —	$ 678	$ —	$ 655	$ —	$ 655
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	5	5	—	—	27	27
Equity securities[1]	378	—	—	378	360	—	—	360
Foreign government debt securities	—	59	—	59	—	57	—	57
U.S. government debt securities	—	23	—	23	—	46	—	46
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[2]	—	184	—	184	—	199	—	199
Total assets	$ 382	$ 1,172	$ 5	$ 1,559	$ 361	$ 1,132	$ 27	$ 1,520
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(13)	(13)
Total liabilities	$ (9)	$ (122)	$ (11)	$ (142)	$ (26)	$ (141)	$ (13)	$ (180)
Net assets (liabilities)[3]	$ 373	$ 1,050	$ (6)	$ 1,417	$ 335	$ 991	$ 14	$ 1,340

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(2) Primarily consists of short-term cash investments.
(3) Excludes $1 million and $44 million as of December 31, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2015 and December 31, 2014:

	Derivative Asset	Derivative Liability	Net Asset/(Liability)
		(In millions)	
January 1, 2014 Balance	$ 3	$ (11)	$ (8)
Unrealized gain (loss)	34	(1)	33
Purchases	15	(16)	(1)
Settlements	(25)	15	(10)
December 31, 2014 Balance	$ 27	$ (13)	$ 14
Unrealized gain (loss)	2	(5)	(3)
Purchases	9	(10)	(1)
Settlements	(33)	17	(16)
December 31, 2015 Balance	$ 5	$ (11)	$ (6)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (6)	Model	RTO auction clearing prices	($3.90) to $5.70	$0.70	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and AFS securities.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of December 31, 2015 and December 31, 2014:

	December 31, 2015[(1)]			December 31, 2014[(2)]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt securities						
FirstEnergy	$ 1,778	$ 16	$ 1,794	$ 1,724	$ 27	$ 1,751
FES	801	9	810	788	13	801
Equity securities						
FirstEnergy	$ 542	$ 34	$ 576	$ 533	$ 58	$ 591
FES	354	24	378	329	31	360

(1) Excludes short-term cash investments: FE Consolidated - $157 million; FES - $139 million.
(2) Excludes short-term cash investments: FE Consolidated - $241 million; FES - $204 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2015, 2014 and 2013 were as follows:

December 31, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 1,534	$ 209	$ (191)	$ (102)	$ 101
FES	733	158	(134)	(90)	57

December 31, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,133	$ 146	$ (75)	$ (37)	$ 96
FES	1,163	113	(54)	(33)	56

December 31, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,047	$ 92	$ (46)	$ (90)	$ 101
FES	940	70	(21)	(79)	60

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2015 and December 31, 2014:

	December 31, 2015			December 31, 2014		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt Securities						
FirstEnergy	$ 6	$ 2	$ 8	$ 13	$ 4	$ 17

The held-to-maturity debt securities contractually mature by June 30, 2017. Investments in employee benefit trusts and equity method investments totaling $255 million as of December 31, 2015 and $626 million as of December 31, 2014, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 20,244	$ 21,519	$ 19,828	$ 21,733
FES	3,027	3,121	3,097	3,241

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2015 and December 31, 2014.

10. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility related to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value (unless they meet the normal purchases and normal sales criteria) as follows:

- Changes in the fair value of derivative instruments that are designated and qualify as cash flow hedges are recorded to AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.
- Changes in the fair value of derivative instruments that are designated and qualify as fair value hedges are recorded as an adjustment to the item being hedged. When fair value hedges are discontinued, the adjustment recorded to the item being hedged is amortized into earnings.
- Changes in the fair value of derivative instruments that are not designated in a hedging relationship are recorded in earnings on a mark-to-market basis, unless otherwise noted.

Derivative instruments meeting the normal purchases and normal sales criteria are accounted for under the accrual method of accounting with their effects included in earnings at the time of contract performance.

FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates.

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $11 million and $8 million as of December 31, 2015 and December 31, 2014, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $1 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $42 million and $50 million as of December 31, 2015 and December 31, 2014, respectively. Based on current estimates, approximately $9 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to Note 2, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of December 31, 2015 and December 31, 2014, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $20 million and $32 million as of December 31, 2015 and December 31, 2014, respectively. During the next twelve months, approximately $10 million of unamortized gains is expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $12 million during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2015, FirstEnergy's net asset position under commodity derivative contracts was $97 million, which related to FES positions. Under these commodity derivative contracts, FES posted $26 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $3 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on derivative contracts held as of December 31, 2015, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next twelve months.

Interest Rate Swaps

As of December 31, 2015 and 2014, no interest rate swaps were outstanding.

NUGs

As of December 31, 2015, FirstEnergy's net liability position under NUG contracts was $136 million representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of December 31, 2015, FirstEnergy's and FES' net liability position under FTRs was $5 million and $6 million, respectively and FES posted $6 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from PJM. PJM has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to PJM, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's Utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets	Fair Value December 31, 2015	Fair Value December 31, 2014	Derivative Liabilities	Fair Value December 31, 2015	Fair Value December 31, 2014
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 150	$ 121	Commodity Contracts	$ (94)	$ (154)
FTRs	7	38	FTRs	(12)	(13)
	157	159		(106)	(167)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs[(1)]	(137)	(153)
Commodity Contracts	78	51	**Noncurrent Liabilities - Other**		
FTRs	1	1	Commodity Contracts	(37)	(13)
NUGs[(1)]	1	2	FTRs	(1)	(1)
	80	54		(175)	(167)
Derivative Assets	$ 237	$ 213	**Derivative Liabilities**	$ (281)	$ (334)

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative assets and derivative liabilities on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

		Amounts Not Offset in Consolidated Balance Sheet		
December 31, 2015	**Fair Value**	**Derivative Instruments**	**Cash Collateral (Received)/Pledged**	**Net Fair Value**
		(In millions)		
Derivative Assets				
Commodity contracts	$ 228	$ (125)	$ —	$ 103
FTRs	8	(8)	—	—
NUG contracts	1	—	—	1
	$ 237	$ (133)	$ —	$ 104
Derivative Liabilities				
Commodity contracts	$ (131)	$ 125	$ 3	$ (3)
FTRs	(13)	8	5	—
NUG contracts	(137)	—	—	(137)
	$ (281)	$ 133	$ 8	$ (140)

December 31, 2014	Fair Value	Amounts Not Offset in Consolidated Balance Sheet		Net Fair Value
		Derivative Instruments	Cash Collateral (Received)/Pledged	
		(In millions)		
Derivative Assets				
Commodity contracts	$ 172	$ (126)	$ —	$ 46
FTRs	39	(14)	—	25
NUG contracts	2	—	—	2
	$ 213	$ (140)	$ —	$ 73
Derivative Liabilities				
Commodity contracts	$ (167)	$ 126	$ 35	$ (6)
FTRs	(14)	14	—	—
NUG contracts	(153)	—	—	(153)
	$ (334)	$ 140	$ 35	$ (159)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2015:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	16	49	(33)	MWH
FTRs	29	—	29	MWH
NUGs	4	—	4	MWH
Natural Gas	83	—	83	mmBTU

The effect of active derivative instruments not in a hedging relationship on the Consolidated Statements of Income during 2015 and 2014 are summarized in the following tables:

	Year Ended December 31,		
	Commodity Contracts	FTRs	Total
		(In millions)	
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[(1)]	$ 93	$ (20)	$ 73
Realized Gain (Loss) Reclassified to:			
Revenues[(2)]	$ 111	$ 50	$ 161
Purchased Power Expense[(3)]	(130)	—	(130)
Other Operating Expense[(4)]	—	(49)	(49)
Fuel Expense	(34)	—	(34)

(1) Includes $93 million for commodity contracts and ($19) million for FTRs associated with FES.

(2) Includes $111 million for commodity contracts and $49 million for FTRs associated with FES.

(3) Includes ($130) million for commodity contracts associated with FES.

(4) Includes ($49) million for FTRs associated with FES.

	Year Ended December 31,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
		(In millions)		
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[(5)]	$ (86)	$ 22	$ —	$ (64)
Realized Gain (Loss) Reclassified to:				
Revenues[(6)]	$ (6)	$ 68	$ —	$ 62
Purchased Power Expense[(7)]	365	—	—	365
Other Operating Expense[(8)]	—	(44)	—	(44)
Fuel Expense	(6)	—	—	(6)
Interest Expense	—	—	14	14

(5) Includes ($86) million for commodity contracts and $21 million for FTRs associated with FES.

(6) Includes ($6) million for commodity contracts and $67 million for FTRs associated with FES.

(7) Realized losses on financially settled wholesale sales contracts of $252 million resulting from higher market prices were netted in purchased power. Includes $365 million for commodity contracts associated with FES.

(8) Includes ($43) million for FTRs associated with FES.

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during 2015 and 2014. Changes in the value of these contracts are deferred for future recovery from (or credit to) customers:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Year Ended December 31, NUGs	Regulated FTRs	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2015	$ (151)	$ 11	$ (140)
Unrealized loss	(47)	(9)	(56)
Purchases	—	12	12
Settlements	62	(13)	49
Outstanding net asset (liability) as of December 31, 2015	$ (136)	$ 1	$ (135)
Outstanding net liability as of January 1, 2014	$ (202)	$ —	$ (202)
Unrealized gain (loss)	(1)	13	12
Purchases	—	11	11
Settlements	52	(13)	39
Outstanding net asset (liability) as of December 31, 2014	$ (151)	$ 11	$ (140)

11. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2015, FirstEnergy's unrestricted retained earnings were $2.3 billion. Dividends declared in 2015 and 2014 were $1.44 per share, which included dividends of $0.36 per share paid in the first, second, third and fourth quarters. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors. On January 19, 2016 the Board of Directors declared a quarterly dividend of $0.36 per share to be paid in the first quarter of 2016.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to their respective parents from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 45%. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' abilities to pay cash dividends to FirstEnergy as of December 31, 2015.

Stock Issuance

In each of 2015 and 2014, FE issued approximately 2.5 million shares of common stock to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2015, as follows:

	Preferred Stock			Preference Stock		
	Shares Authorized	Par Value		Shares Authorized	Par Value	
FirstEnergy	5,000,000	$	100			
OE	6,000,000	$	100	8,000,000		no par
OE	8,000,000	$	25			
Penn	1,200,000	$	100			
CEI	4,000,000		no par	3,000,000		no par
TE	3,000,000	$	100	5,000,000	$	25
TE	12,000,000	$	25			
JCP&L	15,600,000		no par			
ME	10,000,000		no par			
PN	11,435,000		no par			
MP	940,000	$	100			
PE	10,000,000	$	0.01			
WP	32,000,000		no par			

As of December 31, 2015, and 2014, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2015 and 2014:

	As of December 31, 2015		As of December 31	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2015	2014
FirstEnergy:				
FMBs	2016 - 2045	3.340% - 9.740%	$ 3,269	$ 3,190
Secured notes - fixed rate	2016 - 2037	0.679% - 12.000%	2,096	2,247
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			2,098	2,247
Unsecured notes - fixed rate	2016 - 2045	2.150% - 7.700%	13,580	13,078
Unsecured notes - variable rate	2017 - 2020	0.010% - 2.180%	1,292	1,292
Total unsecured notes			14,872	14,370
Capital lease obligations			132	160
Unamortized debt discounts			(18)	(8)
Unamortized fair value adjustments			5	21
Currently payable long-term debt			(1,166)	(804)
Total long-term debt and other long-term obligations			$ 19,192	$ 19,176
FES:				
Secured notes - fixed rate	2016 - 2018	5.625% - 12.000%	$ 340	$ 437
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			342	437
Unsecured notes - fixed rate	2016 - 2039	2.150% - 6.800%	2,593	2,568
Unsecured notes - variable rate	2017 - 2017	0.010% - 0.010%	92	92
Total unsecured notes			2,685	2,660
Capital lease obligations			13	18
Unamortized debt discounts			(1)	(1)
Currently payable long-term debt			(512)	(506)
Total long-term debt and other long-term obligations			$ 2,527	$ 2,608

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used:

(i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

See Note 6, Leases for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. As of December 31, 2015 and 2014, $429 million and $450 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include transition bonds issued by JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. The proceeds were used to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. As of December 31, 2015 and 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. As of December 31, 2015 and 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.

See Note 8, Variable Interest Entities for additional information on securitized bonds.

Other Long-term Debt

The Ohio Companies, Penn, FG and NG each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2015, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $3 million in 2015, all of which relate to Penn. Penn expects to meet its 2016 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2015. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	FirstEnergy	FES
	(In millions)	
2016	$ 1,039	$ 414
2017	1,733	257
2018	1,702	516
2019	2,268	322
2020	1,231	667

The following table classifies the outstanding fixed rate PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

Year	FirstEnergy	FES
	(In millions)	
2016	$ 391	$ 391
2017	222	222
2018	375	375
2019	232	232
2020	490	490

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG is entitled to a credit against its obligation to repay those bonds. FG pays annual fees based on the amounts of the LOCs to the issuing bank and is obligated to reimburse the bank for any drawings thereunder.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2015, are as follows:

	Aggregate LOC Amount (1)	Annual Fees
	(In millions)	
FirstEnergy	$ 93	1.25%
FES	93	1.25%

(1) Includes approximately $1 million of applicable interest coverage.

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2015, FirstEnergy and FES remain in compliance with all debt covenant provisions.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FE financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FE. Also, defaults by FE would generally not cross-default applicable financing arrangements of any of FE's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FE, FG, NG or the Utilities.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET[(2)]	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

(1) FE and the Utilities
(2) Includes FET, ATSI and TrAIL as subsidiary borrowers

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2015:

Borrower	Revolving Credit Facility Sub-Limits	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FE	$ 3,500	$ — (1)
FES	1,500	— (2)
AE Supply	1,000	— (2)
FET	1,000	— (1)
OE	500	500 (3)
CEI	500	500 (3)
TE	500	500 (3)
JCP&L	600	500 (3)
ME	300	500 (3)
PN	300	300 (3)
WP	200	200 (3)
MP	500	500 (3)
PE	150	150 (3)
ATSI	500	500 (3)
Penn	50	100 (3)
TrAIL	400	400 (3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2015 and 2014, were as follows:

	2015	2014
FirstEnergy	2.16%	1.96%
FES	—%	3.34%

13. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2015 and 2014 were as follows:

	2015	2014
	(In millions)	
FirstEnergy	$ 2,282	$ 2,341
FES	$ 1,327	$ 1,365

The following table summarizes the changes to the ARO balances during 2015 and 2014:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2014	$ 1,678	$ 1,015
Liabilities settled	(9)	(7)
Accretion	113	66
Revisions in estimated cash flows	(395)	(233)
Balance, December 31, 2014	$ 1,387	$ 841
Liabilities settled	(13)	(8)
Accretion	92	55
Revisions in estimated cash flows	(56)	(57)
Balance, December 31, 2015	$ 1,410	$ 831

During 2015, FE and FES reduced its ARO by $57 million based on the results of decommissioning cost studies for the Davis-Besse and Perry nuclear generating stations.

During 2014, based on studies by a third-party to reassess the estimated costs of decommissioning certain nuclear generating facilities, FE decreased its ARO by $395 million ($233 million at FES) of which $133 million was credited against a regulatory asset associated with nuclear decommissioning and spent fuel disposal costs for TMI-2. The decrease in the ARO primarily resulted from an extension in the number of years in which decommissioning activities are estimated to occur at Davis-Besse, Perry, TMI-2 and Beaver Valley Units 1 and 2.

14. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);

- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;
- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015. The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016.

Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015, and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, NG, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

15. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $15 million (NG-$15 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $83 million (NG-$81 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of December 31, 2015, outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting of parental guarantees ($583 million), subsidiaries' guarantees ($2,137 million), other guarantees ($300 million) and other assurances ($667 million).

Of this aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $8 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield's Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2015 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 14, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

16. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for FES during the three years ended December 31, 2015 are as follows:

FES	2015	2014	2013
		(In millions)	
Revenues:			
Electric sales to affiliates	$ 664	$ 861	$ 652
Other	6	6	6
Expenses:			
Purchased power from affiliates	353	271	486
Fuel	1	1	—
Support services	705	619	619
Investment Income:			
Interest income from FE	2	3	2
Interest Expense:			
Interest expense to affiliates	4	3	4
Interest expense to FE	3	4	6

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions are generally settled under commercial terms within thirty days. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES and the Utilities are parties to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 5, Taxes).

17. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2015, 2014, and 2013, Condensed Consolidating Balance Sheets as of December 31, 2015 and December 31, 2014, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2015, 2014, and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,824	$ 1,801	$ 2,138	$ (3,758)	$ 5,005
OPERATING EXPENSES:					
Fuel	—	679	192	—	871
Purchased power from affiliates	3,826	—	285	(3,758)	353
Purchased power from non-affiliates	1,684	—	—	—	1,684
Other operating expenses	399	275	618	49	1,341
Pension and OPEB mark-to-market adjustment	(8)	10	55	—	57
Provision for depreciation	12	124	191	(3)	324
General taxes	45	26	27	—	98
Total operating expenses	5,958	1,114	1,368	(3,712)	4,728
OPERATING INCOME (LOSS)	(1,134)	687	770	(46)	277
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	844	17	(5)	(870)	(14)
Miscellaneous income	1	2	—	—	3
Interest expense — affiliates	(29)	(8)	(4)	34	(7)
Interest expense — other	(52)	(104)	(49)	58	(147)
Capitalized interest	—	6	29	—	35
Total other income (expense)	764	(87)	(29)	(778)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(370)	600	741	(824)	147
INCOME TAXES (BENEFITS)	(452)	224	278	15	65
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	(9)	—	(8)	8	(9)
Other comprehensive loss	(18)	(5)	(8)	13	(18)
Income tax benefits on other comprehensive loss	(7)	(2)	(3)	5	(7)
Other comprehensive loss, net of tax	(11)	(3)	(5)	8	(11)
COMPREHENSIVE INCOME	$ 71	$ 373	$ 458	$ (831)	$ 71

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME (LOSS)					
REVENUES	$ 5,990	$ 1,902	$ 2,172	$ (3,920)	$ 6,144
OPERATING EXPENSES:					
Fuel	—	1,055	198	—	1,253
Purchased power from affiliates	3,920	—	271	(3,920)	271
Purchased power from non-affiliates	2,767	4	—	—	2,771
Other operating expenses	790	269	527	49	1,635
Pension and OPEB mark-to-market adjustment	19	90	188	—	297
Provision for depreciation	10	119	193	(3)	319
General taxes	72	31	25	—	128
Total operating expenses	7,578	1,568	1,402	(3,874)	6,674
OPERATING INCOME (LOSS)	(1,588)	334	770	(46)	(530)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(2)	—	(6)
Investment income, including net income from equity investees	791	8	61	(799)	61
Miscellaneous income	2	4	—	—	6
Interest expense — affiliates	(12)	(6)	(4)	15	(7)
Interest expense — other	(53)	(101)	(52)	60	(146)
Capitalized interest	—	4	30	—	34
Total other income (expense)	725	(92)	33	(724)	(58)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(863)	242	803	(770)	(588)
INCOME TAXES (BENEFITS)	(619)	87	298	6	(228)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(244)	155	505	(776)	(360)
Discontinued operations (net of income taxes of $70)	—	116	—	—	116
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(10)	—	—	—	(10)
Change in unrealized gain on available-for-sale securities	21	—	21	(21)	21
Other comprehensive income (loss)	5	(5)	21	(16)	5
Income taxes (benefits) on other comprehensive income (loss)	2	(2)	8	(6)	2
Other comprehensive income (loss), net of tax	3	(3)	13	(10)	3
COMPREHENSIVE INCOME (LOSS)	$ (241)	$ 268	$ 518	$ (786)	$ (241)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 6,068	$ 2,399	$ 1,634	$ (3,928)	$ 6,173
OPERATING EXPENSES:					
Fuel	—	1,056	206	—	1,262
Purchased power from affiliates	4,148	—	266	(3,928)	486
Purchased power from non-affiliates	2,326	7	—	—	2,333
Other operating expenses	635	275	529	48	1,487
Pension and OPEB mark-to-market adjustment	(8)	(37)	(36)	—	(81)
Provision for depreciation	6	127	178	(5)	306
General taxes	80	34	24	—	138
Total operating expenses	7,187	1,462	1,167	(3,885)	5,931
OPERATING INCOME (LOSS)	(1,119)	937	467	(43)	242
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income, including net income from equity investees	847	1	25	(857)	16
Miscellaneous income	4	24	—	—	28
Interest expense — affiliates	(13)	(5)	(6)	14	(10)
Interest expense — other	(63)	(104)	(54)	61	(160)
Capitalized interest	1	2	36	—	39
Total other income (expense)	673	(82)	1	(782)	(190)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(446)	855	468	(825)	52
INCOME TAXES (BENEFITS)	(506)	365	135	12	6
INCOME FROM CONTINUING OPERATIONS	60	490	333	(837)	46
Discontinued operations (net of income taxes of $8)	—	14	—	—	14
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(15)	(13)	—	13	(15)
Amortized gain on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available-for-sale securities	(8)	—	(8)	8	(8)
Other comprehensive loss	(29)	(13)	(8)	21	(29)
Income tax benefits on other comprehensive loss	(11)	(5)	(3)	8	(11)
Other comprehensive loss, net of tax	(18)	(8)	(5)	13	(18)
COMPREHENSIVE INCOME	$ 42	$ 496	$ 328	$ (824)	$ 42

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	275	—	—	—	275
Affiliated companies	433	403	461	(846)	451
Other	36	4	19	—	59
Notes receivable from affiliated companies	406	1,210	805	(2,410)	11
Materials and supplies	53	204	213	—	470
Derivatives	154	—	—	—	154
Collateral	70	—	—	—	70
Prepayments and other	48	18	—	—	66
	1,475	1,841	1,498	(3,256)	1,558
PROPERTY, PLANT AND EQUIPMENT:					
In service	93	6,367	8,233	(382)	14,311
Less — Accumulated provision for depreciation	40	2,144	3,775	(194)	5,765
	53	4,223	4,458	(188)	8,546
Construction work in progress	30	249	878	—	1,157
	83	4,472	5,336	(188)	9,703
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,327	—	1,327
Investment in affiliated companies	7,452	—	—	(7,452)	—
Other	—	10	—	—	10
	7,452	10	1,327	(7,452)	1,337
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	300	16	—	(316)	—
Customer intangibles	61	—	—	—	61
Goodwill	23	—	—	—	23
Property taxes	—	12	28	—	40
Derivatives	79	—	—	—	79
Other	33	318	21	12	384
	496	346	49	(304)	587
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ —	$ 229	$ 308	$ (25)	$ 512
Short-term borrowings-					
Affiliated companies	2,021	389	—	(2,410)	—
Other	—	8	—	—	8
Accounts payable-					
Affiliated companies	884	146	368	(856)	542
Other	21	118	—	—	139
Accrued taxes	7	93	62	(86)	76
Derivatives	103	1	—	—	104
Other	66	61	9	45	181
	3,102	1,045	747	(3,332)	1,562
CAPITALIZATION:					
Total equity	5,605	2,944	4,476	(7,420)	5,605
Long-term debt and other long-term obligations	694	2,122	847	(1,136)	2,527
	6,299	5,066	5,323	(8,556)	8,132
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	791	791
Accumulated deferred income taxes	6	—	697	(103)	600
Asset retirement obligations	—	191	640	—	831
Retirement benefits	27	305	—	—	332
Derivatives	37	1	—	—	38
Other	35	61	803	—	899
	105	558	2,140	688	3,491
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	415	—	—	—	415
Affiliated companies	484	487	674	(1,120)	525
Other	66	21	20	—	107
Notes receivable from affiliated companies	339	838	272	(1,449)	—
Materials and supplies	67	202	223	—	492
Derivatives	147	—	—	—	147
Collateral	229	—	—	—	229
Prepayments and other	48	19	—	1	68
	1,795	1,569	1,189	(2,568)	1,985
PROPERTY, PLANT AND EQUIPMENT:					
In service	133	6,217	7,628	(382)	13,596
Less — Accumulated provision for depreciation	36	2,058	3,305	(191)	5,208
	97	4,159	4,323	(191)	8,388
Construction work in progress	3	206	801	—	1,010
	100	4,365	5,124	(191)	9,398
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,607	—	—	(6,607)	—
Other	—	10	—	—	10
	6,607	10	1,365	(6,607)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	284	98	—	(382)	—
Customer intangibles	78	—	—	—	78
Goodwill	23	—	—	—	23
Property taxes	—	14	27	—	41
Unamortized sale and leaseback costs	—	—	—	—	—
Derivatives	52	—	—	—	52
Other	34	277	7	13	331
	471	389	34	(369)	525
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 18	$ 164	$ 348	$ (24)	$ 506
Short-term borrowings-					
Affiliated companies	1,135	321	28	(1,449)	35
Other	90	9	—	—	99
Accounts payable-					
Affiliated companies	1,068	197	219	(1,068)	416
Other	46	202	—	—	248
Accrued taxes	2	62	161	(123)	102
Derivatives	166	—	—	—	166
Other	72	56	9	47	184
	2,597	1,011	765	(2,617)	1,756
CAPITALIZATION:					
Total equity	5,585	2,561	4,014	(6,575)	5,585
Long-term debt and other long-term obligations	695	2,215	859	(1,161)	2,608
	6,280	4,776	4,873	(7,736)	8,193
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	824	824
Accumulated deferred income taxes	13	—	678	(207)	484
Asset retirement obligations	—	189	652	—	841
Retirement benefits	36	288	—	—	324
Derivatives	14	—	—	—	14
Other	33	69	744	1	847
	96	546	2,074	618	3,334
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (637)	$ 551	$ 1,261	$ (24)	$ 1,151
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	45	296	—	341
Short-term borrowings, net	796	67	—	(863)	—
Redemptions and Repayments-					
Long-term debt	(17)	(70)	(348)	24	(411)
Short-term borrowings, net	—	—	(28)	(98)	(126)
Common stock dividend payment	(70)	—	—	—	(70)
Other	—	(5)	(1)	—	(6)
Net cash provided from (used for) financing activities	709	37	(81)	(937)	(272)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(223)	(399)	—	(627)
Nuclear fuel	—	—	(190)	—	(190)
Proceeds from asset sales	10	3	—	—	13
Sales of investment securities held in trusts	—	—	733	—	733
Purchases of investment securities held in trusts	—	—	(791)	—	(791)
Cash Investments	(10)	—	—	—	(10)
Loans to affiliated companies, net	(67)	(372)	(533)	961	(11)
Other	—	4	—	—	4
Net cash used for investing activities	(72)	(588)	(1,180)	961	(879)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (600)	$ 408	$ 785	$ (22)	$ 571
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	431	447	—	878
Short-term borrowings, net	247	114	—	(361)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	(1)	(269)	(568)	22	(816)
Short-term borrowings, net	—	—	(123)	(178)	(301)
Other	(1)	(12)	(2)	—	(15)
Net cash provided from (used for) financing activities	745	264	(246)	(517)	246
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(169)	(662)	—	(839)
Nuclear fuel	—	—	(233)	—	(233)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	1,163	—	1,163
Purchases of investment securities held in trusts	—	—	(1,219)	—	(1,219)
Loans to affiliated companies, net	(136)	(815)	412	539	—
Other	(1)	5	—	—	4
Net cash used for investing activities	(145)	(672)	(539)	539	(817)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (1,429)	$ 753	$ 776	$ (22)	$ 78
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	864	371	150	(954)	431
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(364)	(90)	22	(1,202)
Short-term borrowings, net	(244)	(505)	—	749	—
Tender premiums	(67)	—	—	—	(67)
Other	(4)	(5)	—	—	(9)
Net cash provided from (used for) financing activities	1,279	(503)	60	(183)	653
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(12)	(256)	(449)	—	(717)
Nuclear fuel	—	—	(250)	—	(250)
Proceeds from asset sales	—	21	—	—	21
Sales of investment securities held in trusts	—	—	940	—	940
Purchases of investment securities held in trusts	—	—	(1,000)	—	(1,000)
Loans to affiliated companies, net	163	(15)	(77)	205	276
Other	(1)	(1)	—	—	(2)
Net cash provided from (used for) investing activities	150	(251)	(836)	205	(732)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

18. SEGMENT INFORMATION

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission and CES.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity. The CES segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment's customers.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates and $1.7 billion was borrowed under the FE revolving credit facility.

Segment Financial Information

For the Years Ended December 31,	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate / Other	Reconciling Adjustments	Consolidated
			(In millions)			
2015						
External revenues	$ 9,625	$ 1,011	$ 4,698	$ (168)	$ (140)	$ 15,026
Internal revenues	—	—	686	—	(686)	—
Total revenues	9,625	1,011	5,384	(168)	(826)	15,026
Depreciation	672	156	394	60	—	1,282
Amortization of regulatory assets, net	261	7	—	—	—	268
Impairment of long-lived assets	8	—	34	—	—	42
Investment income (loss)	42	—	(16)	(9)	(39)	(22)
Impairment of equity method investment	—	—	—	362	—	362
Interest expense	586	161	192	193	—	1,132
Income taxes (benefits)	342	174	50	(262)	11	315
Income (loss) from continuing operations	618	298	89	(427)	—	578
Discontinued operations, net of tax	—	—	—	—	—	—
Net income (loss)	618	298	89	(427)	—	578
Total assets	27,876	7,439	16,365	507	—	52,187
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,108	952	588	56	—	2,704
2014						
External revenues	$ 9,102	$ 769	$ 5,470	$ (146)	$ (146)	$ 15,049
Internal revenues	—	—	819	—	(819)	—
Total revenues	9,102	769	6,289	(146)	(965)	15,049
Depreciation	658	127	387	48	—	1,220
Amortization of regulatory assets, net	1	11	—	—	—	12
Impairment of long-lived assets	—	—	—	—	—	—
Investment income (loss)	56	—	54	2	(40)	72
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	589	131	189	168	(4)	1,073
Income taxes (benefits)	227	121	(223)	(178)	11	(42)
Income (loss) from continuing operations	465	223	(417)	(58)	—	213
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	465	223	(331)	(58)	—	299
Total assets	28,085	6,252	16,518	793	—	51,648
Total goodwill	5,092	526	800	—	—	6,418
Property additions	972	1,329	939	72	—	3,312
2013						
External revenues	$ 8,720	$ 731	$ 5,728	$ (121)	$ (166)	$ 14,892
Internal revenues	—	—	770	—	(770)	—
Total revenues	8,720	731	6,498	(121)	(936)	14,892
Depreciation	606	114	439	43	—	1,202
Amortization of regulatory assets, net	529	10	—	—	—	539
Impairment of long-lived assets	322	—	473	—	—	795
Investment income (loss)	57	—	14	6	(44)	33
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	543	93	222	148	10	1,016
Income taxes (benefits)	301	129	(140)	(105)	10	195
Income (loss) from continuing operations	501	214	(235)	(105)	—	375
Discontinued operations, net of tax	—	—	17	—	—	17
Net income (loss)	501	214	(218)	(105)	—	392
Total assets	27,683	5,247	16,782	712	—	50,424
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,272	461	827	78	—	2,638

19. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million). Pre-tax income for the hydroelectric facilities of $155 million and $26 million (FES - $186 million and $22 million) for the years ended December 31, 2014 and 2013, respectively, was included in discontinued operations in the Consolidated Statement of Income. Included in income for discontinued operations in the year ended December 31, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million and $33 million (FES - $5 million and $31 million) for years ended December 31, 2014 and 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income.

20. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2015 and 2014.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME *(In millions, except per share amounts)*	**2015**				**2014**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 3,541	$ 4,123	$ 3,465	$ 3,897	$ 3,483	$ 3,888	$ 3,496	$ 4,182
Other operating expense	952	850	916	1,057	901	858	1,021	1,182
Pension and OPEB mark-to-market adjustment	242	—	—	—	835	—	—	—
Provision for depreciation	313	328	322	319	316	308	302	294
Operating Income (Loss)	236	908	554	594	(337)	716	292	391
Income (loss) from continuing operations before income taxes (benefits)	(396)	621	302	366	(574)	485	90	170
Income taxes (benefits) [1]	(170)	226	115	144	(268)	152	26	48
Income (loss) from continuing operations	(226)	395	187	222	(306)	333	64	122
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	86
Net Income (Loss)	(226)	395	187	222	(306)	333	64	208
Earnings (loss) per share of common stock-[2]								
Basic - Continuing Operations	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.29
Basic - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.21
Basic - Earnings Available to FirstEnergy Corp.	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.50
Diluted - Continuing Operations	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.29
Diluted - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.20
Diluted - Earnings Available to FirstEnergy Corp.	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.49

(1) - During the fourth quarter of 2014, income tax benefits of $16 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the Company's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period.

(2) - Total quarterly earnings per share information may not equal annual earnings per share due to the issuance of shares throughout the year. See FirstEnergy's Consolidated Statements of Stockholders' Equity and Note 4. Stock-Based Compensation for additional information.

FES

CONSOLIDATED STATEMENTS OF INCOME *(In millions)*	**2015**				**2014**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 1,171	$ 1,338	$ 1,119	$ 1,377	$ 1,342	$ 1,521	$ 1,452	$ 1,829
Other operating expense	329	246	353	413	359	356	468	452
Pension and OPEB mark-to-market adjustment	57	—	—	—	297	—	—	—
Provision for depreciation	84	79	81	80	83	83	79	74
Operating Income (Loss)	25	240	—	12	(321)	90	(151)	(148)
Income (loss) from continuing operations before income taxes (benefits)	(13)	190	(25)	(5)	(347)	72	(154)	(159)
Income taxes (benefits)	1	70	(4)	(2)	(133)	28	(67)	(56)
Income (loss) from continuing operations	(14)	120	(21)	(3)	(214)	44	(87)	(103)
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	116
Net Income (Loss)	(14)	120	(21)	(3)	(214)	44	(87)	13

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The respective management of FirstEnergy and FES, with the participation of each respective registrant's chief executive officer and chief financial officer, have reviewed and evaluated the effectiveness of their registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934, as amended, Rules 13a-15(e) and 15d-15(e), as of the end of the period covered by this report. Based on that evaluation, the chief executive officer and chief financial officer of each registrant have concluded that each respective registrant's disclosure controls and procedures were effective as of the end of the period covered by this report.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control — Integrated Framework* published in 2013, the respective management of each registrant conducted an evaluation of the effectiveness of their registrant's internal control over financial reporting under the supervision of each respective registrant's Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the respective management of each registrant concluded that their registrant's internal control over financial reporting was effective as of December 31, 2015. The effectiveness of FirstEnergy's internal control over financial reporting, as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included herein. The effectiveness of internal control over financial reporting of FES as of December 31, 2015, has not been audited by the registrant's independent registered public accounting firm.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2015, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FirstEnergy's or FES' internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

On February 16, 2016, upon recommendation of its Compensation Committee, the FE Board of Directors (Board) adopted the ESTIP. The ESTIP is a component of the ICP 2015, which was approved by shareholders at the 2015 Annual Meeting of Shareholders. ESTIP awards are cash-based awards granted pursuant to the terms and conditions of the ICP 2015 and payment is based on the successful achievement of corporate financial and operational KPIs. Participants in the ESTIP consist of the executive officers of FE who are deemed to be "covered persons" under Section 162(m) of the Internal Revenue Code of 1986, as amended, and any regulations promulgated thereunder and any other officer or employee selected by the Compensation Committee of the Board (Compensation Committee), which administers the ESTIP. Participants in the ESTIP are ineligible to participate in any other short-term incentive program sponsored by FE, except as provided for in the ICP 2015.

Financial and operational KPIs for the ESTIP are developed in accordance with the performance measures identified in the ICP 2015, and the performance period for awards is January 1st to December 31st of a given year, unless otherwise determined by the Compensation Committee. The Compensation Committee establishes (i) the KPIs that must be satisfied in order for a participant to receive an award for such performance period, including the relative weightings for each KPI with respect to each participant, and (ii) the threshold, target and maximum award opportunity for each participant, which are expressed as a percentage of the participant's base salary. The ESTIP payout will be zero if FE performance is below threshold. Executives are evaluated based on KPIs applicable to FE and their responsibilities within FE.

ESTIP awards are paid no later than March 15th of the year following the year in which the award is earned. If the participant's employment terminates prior to the end of the performance period due to Retirement (as defined in the ESTIP), Disability (as defined in the ICP 2015), death, or termination by FE without Cause (as defined in the ICP 2015), the participant is entitled to receive a pro-rated portion of his or her ESTIP award that would have been earned, based on actual KPI performance, had he or she remained employed through the performance period. However, if the participant is entitled to receive all or a portion of his or her ESTIP award pursuant to an individual agreement or separate severance or change in control plan in which he or she participates, then his or her ESTIP award would be paid pursuant to such individual agreement or plan to avoid any duplication of payments.

The Compensation Committee has the discretion to adjust the payment amount under any award granted under the ESTIP downward (but not upward) without the participant's consent, notwithstanding FE's or the participant's actual performance against the award's performance goals, either on a formula or discretionary basis, or a combination of the two. Subject to the foregoing, the Board or the Compensation Committee may at any time amend, suspend, discontinue, or terminate the ESTIP, so long as no such amendment, suspension, discontinuance or termination materially and adversely affects the rights of any participant in respect of any performance period that has already commenced.

The foregoing description of the ESTIP is qualified in its entirety by reference to the full and complete terms of the ESTIP, which is attached as Exhibit 10-56 to this Annual Report on Form 10-K and incorporated herein by reference, and the ICP 2015, which was filed as Appendix A to FE's Definitive Proxy Statement filed April 1, 2015 and is incorporated herein by reference.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated herein by reference to FirstEnergy's 2016 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to FirstEnergy's 2016 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by Item 12 is incorporated herein by reference to FirstEnergy's 2016 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated herein by reference to FirstEnergy's 2016 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

A summary of the audit and audit-related fees for services rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2015 and 2014, are as follows:

	Audit Fees(1)		Audit-Related Fees(2)	
Company	**2015**	**2014**	**2015**	**2014**
		(In thousands)		
FES	$ 1,810	$ 1,700	$ —	$ —
FE and other subsidiaries	5,812	6,001	150	117
Total FirstEnergy	$ 7,622	$ 7,701	$ 150	$ 117

(1) Professional services rendered for the audits of the registrants' annual financial statements and reviews of unaudited financial statements included in the registrants' Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters, agreed upon procedures and consents for financings and filings made with the SEC.

(2) Professional services rendered in 2015 and 2014 related to SEC Regulation AB. Also, in 2014, professional services rendered related to additional agreed upon procedures for the audit of compliance with certain DOE grants, risk assurance and the audit of PE's cost allocation manual.

Tax Fees and All Other Fees

There were no tax services performed by PricewaterhouseCoopers LLP in 2015 or 2014. PricewaterhouseCoopers LLP performed no other services in 2015 or 2014, however, the registrants paid approximately $15,000 (fifteen-thousand) and $5,000 (five-thousand) in software subscription fees to PricewaterhouseCoopers LLP for 2015 and 2014, respectively.

Additional information required by this item is incorporated herein by reference to FirstEnergy's 2016 Proxy Statement to be filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

1. Financial Statements:

Management's Report on Internal Control Over Financial Reporting for FirstEnergy Corp. and FES is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm for FirstEnergy Corp. and FES are listed under Item 8 herein.

The financial statements filed as a part of this report for FirstEnergy Corp. and FES are listed under Item 8 herein.

2. Financial Statement Schedules:

Reports of Independent Registered Public Accounting Firm as to Schedules are included herein on pages:

	Page
FirstEnergy	112
FES	113

Schedule II — Consolidated Valuation and Qualifying Accounts are included herein on pages:

	Page
FirstEnergy	212
FES	213

3. Exhibits — FirstEnergy

Exhibit Number	
2-1 †	Agreement and Plan of Merger, dated as of February 10, 2010, by and among FirstEnergy Corp., Element Merger Sub, Inc. and Allegheny Energy, Inc. (incorporated by reference to FE's Form 8-K filed February 11, 2010, Exhibit 2.1, File No. 333-21011).
3-1	Amended Articles of Incorporation of FirstEnergy Corp. (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 3-1, File No. 333-21011).
3-2	Amendment to the Amended Articles of Incorporation of FirstEnergy Corp. dated as of February 25, 2011 (incorporated by reference to FE's Form 8-K filed February 25, 2011, Exhibit 3.1, File No. 333-21011).
3-3	FirstEnergy Corp. Amended Code of Regulations. (incorporated by reference to FE's Form 10-K filed February 25, 2009, Exhibit 3.1, File No. 333-21011).
3-4	Amendment to the FirstEnergy Corp. Amended Code of Regulations (incorporated by reference to FirstEnergy's Definitive Proxy Statement filed April 1, 2011, Appendix 1, File No. 333-21011).
4-1	Indenture, dated November 15, 2001, between FirstEnergy Corp. and The Bank of New York Mellon, as Trustee. (incorporated by reference to FE's Form S-3 filed September 21, 2001, Exhibit 4(a), File No. 333-69856).
4-2	Officer's Certificate relating to $650 million aggregate principal amount of the Company's 2.75% Notes, Series A, due 2018 (the "Series A Notes") and $850 million aggregate principal amount of the Company's 4.25% Notes, Series B, due 2023 (the "Series B Notes") (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.1, File No. 333-21011.)
4-2 (a)	Form of Series A Note (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.2, File No. 333-21011)
4-2 (b)	Form of Series B Note, (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.3, File No. 333-21011).
4-3	Agreement of Resignation, Appointment and Acceptance Among The Bank of New York Mellon, as Resigning Trustee, The Bank of New York Mellon Trust Company, N.A., as Successor Trustee and FirstEnergy Corp., dated May 16, 2012 (incorporated by reference to FE's Form S-3 filed May 18, 2012, Exhibit 4(h), file No. 333-181519).
(B) 10-1	FirstEnergy Corp. 2007 Incentive Plan, effective May 15, 2007. (incorporated by reference to FE's Form 10-K filed February 25, 2009, Exhibit 10.1, File No. 333-21011).
(B) 10-2	Amendment to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2011. (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.5, File No. 333-21011).
(B) 10-3	Amendment No. 2 to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-3 File No. 333-21011).
(B) 10-4	Form of 2014-2016 Performance Share Award Agreement (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-4 File No. 333-21011).
(B) 10-5	Form of 2014-2016 Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-5 File No. 333-21011).
(B) 10-6	FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-6 File No. 333-21011).
(B) 10-7	Amendment No. 1 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective as of January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.7, File No. 333-21011).
(B) 10-8	Amendment No. 2 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective January 21, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-8 File No. 333-21011).
(B) 10-9	FirstEnergy Corp. Supplemental Executive Retirement Plan, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-9 File No. 333-21011).
(B) 10-10	Amendment to FirstEnergy Corp. Supplemental Executive Retirement Plan, effective January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.8, File No. 333-21011).
(B) 10-11	FirstEnergy Corp. Cash Balance Restoration Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-11 File No. 333-21011).

Exhibit Number	
(B) 10-12	FirstEnergy Corp. Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-12 File No. 333-21011)
(B) 10-13	Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000 (incorporated by reference to GPU, Inc. Form 10-K filed March 21, 2001, Exhibit 10-N, File No. 001-06047).
10-14	Consent Decree dated March 18, 2005. (incorporated by reference to FE's Form 8-K filed March 18, 2005, Exhibit 10-1, File No. 333-21011).
(B) 10-15	Form of 2010-2012 Performance Share Award Agreement effective January 1, 2010 (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 10-48, File No. 333-21011).
(B) 10-16	Form of Performance-Adjusted Restricted Stock Unit Award Agreement as of March 8, 2010 (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 10-49, File No. 333-21011).
(B) 10-17	Form of Director Indemnification Agreement (incorporated by reference to FE's 10-Q filed May 7, 2009, Exhibit 10.1, File No. 333-21011).
(B) 10-18	Form of Management Director Indemnification Agreement (incorporated by reference to FE's 10-Q filed May 7, 2009, Exhibit 10.2, File No. 333-21011).
(B) 10-19	FirstEnergy Corp. Change in Control Severance Plan (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.9, File No. 333-21011).
(B) 10-20	Allegheny Energy, Inc. 1998 Long-Term Incentive Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.2, File No. 21011).
(B) 10-21	Amendment No. 1 to Allegheny Energy, Inc. 1998 Long-Term Incentive Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-25 File No. 333-21011).
(B) 10-22	Allegheny Energy, Inc. 2008 Long-Term Incentive Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.3, File No. 21011).
(B) 10-23	Amendment No. 1 to Allegheny Energy, Inc. 2008 Long-Term Incentive Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-27 File No. 333-21011).
(B) 10-24	Allegheny Energy, Inc. Non-Employee Director Stock Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.4, File No. 21011).
(B) 10-25	Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-29 File No. 333-21011).
(B) 10-26	Amendment No. 1 to Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-30 File No. 333-21011).
10-27	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein. (incorporated by reference to FE's Form 10-Q filed August 2, 2011, Exhibit 10.1, File No. 333-21011).
10-28	Amendment, dated as of May 8, 2012, to the Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE's Form 8-K filed May 11, 2012, Exhibit 10.2, File No. 333-21011).
10-29	Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 8-K filed May 13, 2013, Exhibit 10.1, File No. 333-21011).

Exhibit Number	
10-30	Amendment, dated as of October 31, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 10-Q filed November 5, 2013, Exhibit 10.1(a), File No. 333-21011).
10-31	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, May 8, 2013 and October 31, 2013, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 8-K filed April 4, 2014, Exhibit 10.1, File No. 333-21011).
(B) 10-32	Employment Agreement between FirstEnergy Corp. and Anthony J. Alexander, dated March 20, 2012. (incorporated by reference to FE's Form 10-Q filed March 31, 2012, Exhibit 10.1, File No. 333-21011).
(B) 10-33	Form of Officer Indemnification Agreement (incorporated by reference to FirstEnergy's Form 8-K filed July 23, 2012, Exhibit 10.1, File No. 333-21011).
(B) 10-34	Amendment No.1 to the FirstEnergy Corp. Change in Control Severance Plan, amended and restated as of September 18, 2012 (incorporated by reference to FE's Form 10-Q filed November 8, 2012, Exhibit 10.1, File No. 333-21011).
10-35	U.S. $1,000,000,000 Credit Agreement, dated as of May 8, 2012, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed May 11, 2012, Exhibit 10.3, File No. 333-21011).
10-36	Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of May 8, 2012, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed May 13, 2013, Exhibit 10.3, File No. 333-21011).
10-37	Amendment, dated as of March 31, 2014 to the Credit Agreement, dated as of May 8, 2012, and as amended as of May 8, 2013, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10.3, File No. 333-21011).
10-38	Term Loan Credit Agreement, dated as of March 31, 2014, among FE, as borrower, the banks named therein and The Royal Bank of Scotland, plc, as administrative agent (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10.4, File No. 333-21011).
10-39	Guarantee, dated as of September 16, 2013 by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Executive Deferred Compensation Plan (incorporated by reference to FE's Form 10-Q filed November 5, 2013, Exhibit 10.2, File No. 333-21011).
(B) 10-40	Executive Severance Benefits Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-44 File No. 333-21011).
(B) 10-41	Amendment No. 2 to the FirstEnergy Corp. Change in Control Severance Plan (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-44, File No. 333-21011).
(B) 10-42	Amendment No. 1 to the FirstEnergy Corp. Executive Deferred Compensation Plan, dated as of January 23, 2014 (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-45, File No. 333-21011).
(B) 10-43	Executive Short-Term Incentive Program (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-46, File No. 333-21011).
(B) 10-44	Form of 2015-2017 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-47, File No. 333-21011).
(B) 10-45	Form of 2015-2017 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-48, File No. 333-21011).

Exhibit Number	
(B) 10-46	Form of Restricted Stock Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-49, File No. 333-21011).
(B) 10-47	FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated July 20, 2015, and effective as of November 1, 2015 (incorporated by reference to FE's Form 8-K filed July 24, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-48	Performance-Earned Restricted Stock Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James F. Pearson (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-49	Performance-Earned Cash Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James H. Lash (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-50	FirstEnergy Corp. 2017 Change in Control Severance Plan, dated as of September 15, 2015, and effective as of January 1, 2017 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-51	Waiver of Participation in the FirstEnergy Corp. Change in Control Severance Plan, entered into by Charles E. Jones dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-52	Non-Competition and Non-Disparagement Agreement, dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.3, File No. 333-21011).
(B) 10-53	2015-2017 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement between FirstEnergy Corp. and Anthony J. Alexander, effective March 2, 2015 (incorporated by reference to FE's Form 10-Q filed May 1, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-54	2015-2017 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement between FirstEnergy Corp. and Anthony J. Alexander, effective March 2, 2015 (incorporated by reference to FE's Form 10-Q filed May 1, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-55	FirstEnergy Corp. 2015 Incentive Compensation Plan (incorporated by reference to FirstEnergy's Definitive Proxy Statement filed April 1, 2015, Appendix A, File No. 333-21011).
(A)(B) 10-56	Executive Short-Term Incentive Program, effective February 16, 2016.
(A)(B) 10-57	Form of 2016-2018 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A)(B) 10-58	Form of 2016-2018 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A)(B) 10-59	Form of 2016 Restricted Stock Award Agreement
(A) 12	Consolidated ratios of earnings to fixed charges.
(A) 21	List of Subsidiaries of the Registrant at December 31, 2015.
(A) 23	Consent of Independent Registered Public Accounting Firm.
(A) 31-1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 31-2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
101	The following materials from the Annual Report on Form 10-K for FirstEnergy Corp. for the period ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

† Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Registrant will furnish the omitted schedules to the Securities and Exchange Commission upon request by the Commission.

(A) Provided herein in electronic format as an exhibit.

(B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, FirstEnergy has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but hereby agrees to furnish to the SEC on request any such documents.

3. Exhibits — FES

Exhibit Number	
3-1	Articles of Incorporation of FirstEnergy Solutions Corp., as amended August 31, 2001. (incorporated by reference to FES' Form S-4 filed August 6, 2007, Exhibit 3.2, File No. 333-145140-01).
3-2	Amended and Restated Code of Regulations of FirstEnergy Solutions Corp. effective as of August 26, 2009 (incorporated by reference to FES' Form 8-K filed August 27, 2009, Exhibit 3.1, File No. 000-53742).
4-1	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 19, 2008, of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) to The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1, File No. 333-145140-01).
4-1 (a)	First Supplemental Indenture dated as of June 25, 2008 (including Form of First Mortgage Bonds, Guarantee Series A of 2008 due 2009 and Form of First Mortgage Bonds, Guarantee Series B of 2008 due 2009). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(a), File No. 333-145140-01).
4-1 (b)	Second Supplemental Indenture dated as of March 1, 2009 (including Form of First Mortgage Bonds, Guarantee Series A of 2009 due 2014 and Form of First Mortgage Bonds, Guarantee Series B of 2009 due 2023). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(b), File No. 333-145140-01).
4-1 (c)	Third Supplemental Indenture dated as of March 31, 2009 (including Form of First Mortgage Bonds, Collateral Series A of 2009 due 2011). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(c), File No. 333-145140-01).
4-1 (d)	Fourth Supplemental Indenture, dated as of June 15, 2009 (including Form of First Mortgage Bonds, Guarantee Series C of 2009 due 2018, Form of First Mortgage Bonds, Guarantee Series D of 2009 due 2029, Form of First Mortgage Bonds, Guarantee Series E of 2009 due 2029, Form of First Mortgage Bonds, Collateral Series B of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series C of 2009 due 2011). (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.3, File No. 333-145140-01).
4-1 (e)	Fifth Supplemental Indenture, dated as of June 30, 2009 (including Form of First Mortgage Bonds, Guarantee Series F of 2009 due 2047, Form of First Mortgage Bonds, Guarantee Series G of 2009 due 2018 and Form of First Mortgage Bonds, Guarantee Series H of 2009 due 2018). (incorporated by reference to FES' Form 8-K filed July 6, 2009, Exhibit 4.2, File No. 333-145140-01).
4-1 (f)	Sixth Supplemental Indenture, dated as of December 1, 2009 (including Form of First Mortgage Bonds, Collateral Series D of 2009 due 2012) (incorporated by reference to FES' Form 8-K filed December 4, 2009, Exhibit 4.2, File No. 000-53742).
4-1 (g)	Seventh Supplemental Indenture dated as of February 14, 2012 (including Form of First Mortgage Bonds, Collateral Series D of 2009 due 2012) (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 4.1(g), File No. 000-53742).
4-2	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009, by and between FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.1, File No. 333-145140-01).
4-2 (a)	First Supplemental Indenture, dated as of June 15, 2009 (including Form of First Mortgage Bonds, Guarantee Series A of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series B of 2009 due 2011, Form of First Mortgage Bonds, Collateral Series A of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series B of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series C of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series D of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series E of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series F of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series G of 2009 due 2011). (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.2(i), File No. 333-145140-01).
4-2 (b)	Second Supplemental Indenture, dated as of June 30, 2009 (including Form of First Mortgage Bonds, Guarantee Series C of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series D of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series E of 2009 due 2033, Form of First Mortgage Bonds, Collateral Series H of 2009 due 2011, Form of First Mortgage Bonds, Collateral Series I of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series J of 2009 due 2010). (incorporated by reference to FES' Form 8-K filed July 6, 2009, Exhibit 4.1, File No. 333-145140-01).
4-2 (c)	Third Supplemental Indenture, dated as of December 1, 2009 (including Form of First Mortgage Bonds, Collateral Series K of 2009 due 2012). (incorporated by reference to FES' Form 8-K filed December 4, 2009, Exhibit 4.1, File No. 000-53742).

Exhibit Number	
4-2 (d)	Fourth Supplemental Indenture, dated as of February 14, 2012 (including Form of First Mortgage Bonds, Collateral Series K of 2009 due 2012). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 4.2(d), File No. 000-53742).
4-3	Indenture, dated as of August 1, 2009, between FirstEnergy Solutions Corp. and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to FES' Form 8-K filed August 7, 2009, Exhibit 4.1, File No. 000-53742).
4-3 (a)	First Supplemental Indenture, dated as of August 1, 2009 (including Form of 4.80% Senior Notes due 2015, Form of 6.05% Senior Notes due 2021 and Form of 6.80% Senior Notes due 2039). (incorporated by reference to FES' Form 8-K filed August 7, 2009, Exhibit 4.2, File No. 000-53742).
10-1	Form of 6.85% Exchange Certificate due 2034. (incorporated by reference to FES' Form S-4 filed August 6, 2007, Exhibit 4.1, File No. 333-145140-01).
10-2	Guaranty of FirstEnergy Solutions Corp., dated as of July 1, 2007. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-9, File No. 333-21011).
10-3	Indenture of Trust, Open-End Mortgage and Security Agreement, dated as of July 1, 2007, between the applicable Lessor and The Bank of New York Trust Company, N.A., as Indenture Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-3, File No. 333-21011).
10-4	6.85% Lessor Note due 2034. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-3, File No. 333-21011).
10-5	Participation Agreement, dated as of June 26, 2007, among FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), as Lessee, FirstEnergy Solutions Corp., as Guarantor, the applicable Lessor, U.S. Bank Trust National Association, as Trust Company, the applicable Owner Participant, The Bank of New York Trust Company, N.A., as Indenture Trustee, and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-1, File No. 333-21011).
10-6	Trust Agreement, dated as of June 26, 2007, between the applicable Owner Participant and U.S. Bank Trust National Association, as Owner Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-2, File No. 333-21011).
10-7	Pass Through Trust Agreement, dated as of June 26, 2007, among FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), FirstEnergy Solutions Corp., and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-12, File No. 333-21011).
10-8	Bill of Sale and Transfer, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-5, File No. 333-21011).
10-9	Facility Lease Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-6, File No. 333-21011).
10-10	Site Lease, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-7, File No. 333-21011).
10-11	Site Sublease, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-8, File No. 333-21011).
10-12	Support Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-10, File No. 333-21011).
10-13	Second Amendment to the Bruce Mansfield Units 1, 2, and 3 Operating Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), The Cleveland Electric Illuminating Company and The Toledo Edison Company. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-11, File No. 333-21011).
10-14	Guaranty, dated as of March 26, 2007, by FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) on behalf of FirstEnergy Solutions Corp. (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.39, File No. 333-145140-01).

Exhibit Number	
10-15	Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.40, File No. 333-145140-01).
10-16	Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.41, File No. 333-145140-01).
10-17	Guaranty, dated as of March 26, 2007, by FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) on behalf of FirstEnergy Solutions Corp. (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.42, File No. 333-145140-01).
(B) 10-18	Form of Trust Indenture dated as of December 1, 2005 between Ohio Water Development Authority and JP Morgan Trust Company, as Trustee, related to issuance of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) pollution control revenue refunding bonds. (incorporated by reference to FE's Form 10-K filed March 2, 2006, Exhibit 10-59, File No. 333-21011).
(B) 10-19	Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.), dated as of December 1, 2005. (incorporated by reference to FE's Form 10-K filed March 2, 2006, Exhibit 10-63, File No. 333-21011).
(C) 10-20	Form of Trust Indenture dated as of April 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing pollution control revenue refunding bonds issued on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FE's Form 10-Q filed May 9, 2006, Exhibit 10-3, File No. 333-21011).
(C) 10-21	Form of Waste Water Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) dated as of April 1, 2006. (incorporated by reference to FE's Form 10-Q filed May 9, 2006, Exhibit 10-4, File No. 333-21011).
(D) 10-22	Form of Trust Indenture dated as of December 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing State of Ohio Pollution Control Revenue Refunding Bonds (FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.)) (FirstEnergy Nuclear Generation Project). (incorporated by reference to FE's Form 10-K filed February 28, 2007, Exhibit 10-77, File No. 333-21011).
(D) 10-23	Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) dated as of December 1, 2006. (incorporated by reference to FE's Form 10-K filed February 28, 2007, Exhibit 10-80, File No. 333-21011).
(B) 10-24	First Amendment to Loan Agreement, dated as of February 14, 2012, between the Ohio Water Development Authority, as issuer, and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Generation Corp.). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 10.1, File No. 000-53742).
(B) 10-25	First Amendment to Loan Agreement, dated as of February 14, 2012, between the Ohio Air Quality Development Authority, as issuer, and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 10.2, File No. 000-53742).
10-26	First Supplemental Trust Indenture, dated April 2, 2012, supplementing and amending that certain Trust Indenture dated as of April 1, 2006 between the Ohio Water Development Authority and The Bank of New York Mellon Trust Company, N.A. as Trustee securing pollution control revenue refunding bonds issued on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (FirstEnergy Generation Project), which trust indenture, as amended, is substantially similar to various other PCRB trust indentures of FirstEnergy Generation, LLC (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.1, File No. 000-53742).
10-27	First Amendment to Loan Agreement dated April 2, 2012, amending the Waste Water Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), dated as of April 1, 2006, which loan agreement, as amended, is substantially similar to various other PCRB loan agreements of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.2, File No. 000-53742).
10-28	First Supplemental Trust Indenture, dated April 2, 2012, supplementing and amending that certain Trust Indenture dated as of December 1, 2006 between the Ohio Water Development Authority and The Bank of New York Mellon Trust Company, N.A., as Trustee securing State of Ohio Pollution Control Revenue Refunding Bonds (FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.)) (FirstEnergy Nuclear Generation Project), which trust indenture, as amended, is substantially similar to various other PCRB trust indentures of FirstEnergy Nuclear Generation, LLC (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.3, File No. 000-53742).

Exhibit Number	
10-29	First Amendment to Loan Agreement dated April 2, 2012, amending the Waste Water Facilities and Solid Waste Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.), dated as of December 1, 2006, which loan agreement, as amended, is substantially similar to various other PCRB loan agreements of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.4, File No. 000-53742).
10-30	Credit Agreement, dated as of June 17, 2011, among FirstEnergy Solutions Corp., and Allegheny Energy Supply Company, LLC, as borrowers, JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein. (incorporated by reference to FES' Form 10-Q filed August 2, 2011, Exhibit 10.1, File No. 000-53742).
10-31	Amendment, dated as of May 8, 2012, to the Credit Agreement, dated as of June 17, 2011, among FirstEnergy Solutions Corp., and Allegheny Energy Supply Company, LLC, as borrowers, JP Morgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed May 11, 2012, Exhibit 10.3, File No. 000-53742).
10-32	Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011 and May 8, 2012, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed May 13, 2013, Exhibit 10.2, File No. 000-53742).
10-33	Amendment, dated as of October 31, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011 and May 8, 2012 and May 8, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 10-Q filed November 5, 2013, Exhibit 10.1(b), File No. 000-53742).
10-34	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011, May 8, 2012 and May 8, 2013 and October 31, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed April 4, 2014, Exhibit 10.2, File No. 000-53742).
(A) 31-1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 31-2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
101	The following materials from the Annual Report on Form 10-K for FirstEnergy Solutions Corp. for the period ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
(A)	Provided herein in electronic format as an exhibit.
(B)	Four substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to four other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, the Ohio Air Quality Authority and Beaver County Industrial Development Authority, Pennsylvania, relating to pollution control notes of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).
(C)	Three substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to three other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority and the Beaver County Industrial Development Authority relating to pollution control notes of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).
(D)	Seven substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to one other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, three other series of pollution control bonds issued by the Ohio Air Quality Development Authority and the three other series of pollution control bonds issued by the Beaver County Industrial Development Authority, relating to pollution control notes of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, FES has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but hereby agrees to furnish to the SEC on request any such documents.

SCHEDULE II

FIRSTENERGY CORP.

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts [1]	Deductions [2]	Ending Balance
			(In thousands)		
Year Ended December 31, 2015:					
Accumulated provision for uncollectible accounts — customers	$ 59,266	$ 114,249	$ 54,199	$ 158,939	$ 68,775
— other	$ 5,197	$ 899	$ 4,189	$ 5,054	$ 5,231
Loss carryforward tax valuation reserve	$ 174,004	$ 18,393	$ —	$ —	$ 192,397
Year Ended December 31, 2014:					
Accumulated provision for uncollectible accounts — customers	$ 51,630	$ 90,144	$ 36,373	$ 118,881	$ 59,266
— other	$ 2,976	$ 3,469	$ 8,264	$ 9,512	$ 5,197
Loss carryforward tax valuation reserve	$ 125,360	$ 48,644	$ —	$ —	$ 174,004
Year Ended December 31, 2013:					
Accumulated provision for uncollectible accounts — customers	$ 40,354	$ 68,733	$ 39,775	$ 97,232	$ 51,630
— other	$ 4,013	$ (1,464)	$ 5,208	$ 4,781	$ 2,976
Loss carryforward tax valuation reserve	$ 101,697	$ 23,663	$ —	$ —	$ 125,360

(1) Represents recoveries and reinstatements of accounts previously written off.
(2) Represents the write-off of accounts considered to be uncollectible.

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2015, 2014 AND 2013

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts (1)	Deductions (2)	Ending Balance
			(In thousands)		
Year Ended December 31, 2015:					
Accumulated provision for uncollectible accounts — customers	$ 17,862	$ 7,411	$ —	$ 16,807	$ 8,466
— other	$ 2,500	$ —	$ —	$ —	$ 2,500
Loss carryforward tax valuation reserve	$ 32,126	$ 13,682	$ —	$ —	$ 45,808
Year Ended December 31, 2014:					
Accumulated provision for uncollectible accounts — customers	$ 11,073	$ 21,942	$ —	$ 15,153	$ 17,862
— other	$ 2,523	$ 9	$ —	$ 32	$ 2,500
Loss carryforward tax valuation reserve	$ 26,875	$ 5,251	$ —	$ —	$ 32,126
Year Ended December 31, 2013:					
Accumulated provision for uncollectible accounts — customers	$ 16,188	$ 14,294	$ —	$ 19,409	$ 11,073
— other	$ 2,500	$ 28	$ —	$ 5	$ 2,523
Loss carryforward tax valuation reserve	$ 15,810	$ 11,065	$ —	$ —	$ 26,875

(1) Represents recoveries and reinstatements of accounts previously written off.
(2) Represents the write-off of accounts considered to be uncollectible.

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.

FIRSTENERGY CORP.

BY: /s/ Charles E. Jones
Charles E. Jones
President and Chief Executive Officer

Date: February 16, 2016

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Charles E. Jones
Charles E. Jones
President and Chief Executive Officer and Director
(Principal Executive Officer)

/s/ George M. Smart
George M. Smart
Director
(Non-Executive Chairman of Board)

/s/ James F. Pearson
James F. Pearson
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ K. Jon Taylor
K. Jon Taylor
Vice President, Controller and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Paul T. Addison
Paul T. Addison
Director

/s/ Donald T. Misheff
Donald T. Misheff
Director

/s/ Michael J. Anderson
Michael J. Anderson
Director

/s/ Thomas N. Mitchell
Thomas N. Mitchell
Director

/s/ William T. Cottle
William T. Cottle
Director

/s/ Ernest J. Novak, Jr.
Ernest J. Novak, Jr.
Director

/s/ Robert B. Heisler, Jr.
Robert B. Heisler, Jr.
Director

/s/ Christopher D. Pappas
Christopher D. Pappas
Director

/s/ Julia L. Johnson
Julia L. Johnson
Director

/s/ Luis A. Reyes
Luis A. Reyes
Director

/s/ Ted J. Kleisner
Ted J. Kleisner
Director

/s/ Jerry Sue Thornton
Jerry Sue Thornton
Director

Date: February 16, 2016

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.

FIRSTENERGY SOLUTIONS CORP.

BY: /s/ Donald R. Schneider
Donald R. Schneider
President

Date: February 16, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Donald R. Schneider
Donald R. Schneider
President
(Principal Executive Officer)

/s/ James F. Pearson
James F. Pearson
Executive Vice President and Chief Financial Officer, Director
(Principal Financial Officer)

/s/ Charles E. Jones
Charles E. Jones
Director

/s/ K. Jon Taylor
K. Jon Taylor
Vice President and Controller
(Principal Accounting Officer)

/s/ James H. Lash
James H. Lash
Director

Date: February 16, 2016

Exhibit Index

FirstEnergy

Exhibit Number		
2-1 †		Agreement and Plan of Merger, dated as of February 10, 2010, by and among FirstEnergy Corp., Element Merger Sub, Inc. and Allegheny Energy, Inc. (incorporated by reference to FE's Form 8-K filed February 11, 2010, Exhibit 2.1, File No. 333-21011).
3-1		Amended Articles of Incorporation of FirstEnergy Corp. (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 3-1, File No. 333-21011).
3-2		Amendment to the Amended Articles of Incorporation of FirstEnergy Corp. dated as of February 25, 2011 (incorporated by reference to FE's Form 8-K filed February 25, 2011, Exhibit 3.1, File No. 333-21011).
3-3		FirstEnergy Corp. Amended Code of Regulations. (incorporated by reference to FE's Form 10-K filed February 25, 2009, Exhibit 3.1, File No. 333-21011).
3-4		Amendment to the FirstEnergy Corp. Amended Code of Regulations (incorporated by reference to FirstEnergy's Definitive Proxy Statement filed April 1, 2011, Appendix 1, File No. 333-21011).
4-1		Indenture, dated November 15, 2001, between FirstEnergy Corp. and The Bank of New York Mellon, as Trustee. (incorporated by reference to FE's Form S-3 filed September 21, 2001, Exhibit 4(a), File No. 333-69856).
4-2		Officer's Certificate relating to $650 million aggregate principal amount of the Company's 2.75% Notes, Series A, due 2018 (the "Series A Notes") and $850 million aggregate principal amount of the Company's 4.25% Notes, Series B, due 2023 (the "Series B Notes") (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.1, File No. 333-21011.)
4-2	(a)	Form of Series A Note (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.2, File No. 333-21011)
4-2	(b)	Form of Series B Note, (incorporated by reference to FE's Form 8-K filed March 5, 2013, Exhibit 4.3, File No. 333-21011).
4-3		Agreement of Resignation, Appointment and Acceptance Among The Bank of New York Mellon, as Resigning Trustee, The Bank of New York Mellon Trust Company, N.A., as Successor Trustee and FirstEnergy Corp., dated May 16, 2012 (incorporated by reference to FE's Form S-3 filed May 18, 2012, Exhibit 4(h), file No. 333-181519).
(B) 10-1		FirstEnergy Corp. 2007 Incentive Plan, effective May 15, 2007. (incorporated by reference to FE's Form 10-K filed February 25, 2009, Exhibit 10.1, File No. 333-21011).
(B) 10-2		Amendment to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2011. (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.5, File No. 333-21011).
(B) 10-3		Amendment No. 2 to FirstEnergy Corp. 2007 Incentive Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-3 File No. 333-21011).
(B) 10-4		Form of 2014-2016 Performance Share Award Agreement (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-4 File No. 333-21011).
(B) 10-5		Form of 2014-2016 Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-5 File No. 333-21011).
(B) 10-6		FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-6 File No. 333-21011).
(B) 10-7		Amendment No. 1 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective as of January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.7, File No. 333-21011).
(B) 10-8		Amendment No. 2 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, effective January 21, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-8 File No. 333-21011).
(B) 10-9		FirstEnergy Corp. Supplemental Executive Retirement Plan, amended and restated January 1, 2005, further amended December 31, 2010 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-9 File No. 333-21011).
(B) 10-10		Amendment to FirstEnergy Corp. Supplemental Executive Retirement Plan, effective January 1, 2012 (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.8, File No. 333-21011).

(B) 10-11 FirstEnergy Corp. Cash Balance Restoration Plan, effective January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-11 File No. 333-21011).

(B) 10-12 FirstEnergy Corp. Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2014 (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-12 File No. 333-21011)

(B) 10-13 Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000 (incorporated by reference to GPU, Inc. Form 10-K filed March 21, 2001, Exhibit 10-N, File No. 001-06047).

10-14 Consent Decree dated March 18, 2005. (incorporated by reference to FE's Form 8-K filed March 18, 2005, Exhibit 10-1, File No. 333-21011).

(B) 10-15 Form of 2010-2012 Performance Share Award Agreement effective January 1, 2010 (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 10-48, File No. 333-21011).

(B) 10-16 Form of Performance-Adjusted Restricted Stock Unit Award Agreement as of March 8, 2010 (incorporated by reference to FE's Form 10-K filed February 19, 2010, Exhibit 10-49, File No. 333-21011).

(B) 10-17 Form of Director Indemnification Agreement (incorporated by reference to FE's 10-Q filed May 7, 2009, Exhibit 10.1, File No. 333-21011).

(B) 10-18 Form of Management Director Indemnification Agreement (incorporated by reference to FE's 10-Q filed May 7, 2009, Exhibit 10.2, File No. 333-21011).

(B) 10-19 FirstEnergy Corp. Change in Control Severance Plan (incorporated by reference to FE's Form 10-Q filed May 3, 2011, Exhibit 10.9, File No. 333-21011).

(B) 10-20 Allegheny Energy, Inc. 1998 Long-Term Incentive Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.2, File No. 21011).

(B) 10-21 Amendment No. 1 to Allegheny Energy, Inc. 1998 Long-Term Incentive Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-25 File No. 333-21011).

(B) 10-22 Allegheny Energy, Inc. 2008 Long-Term Incentive Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.3, File No. 21011).

(B) 10-23 Amendment No. 1 to Allegheny Energy, Inc. 2008 Long-Term Incentive Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-27 File No. 333-21011).

(B) 10-24 Allegheny Energy, Inc. Non-Employee Director Stock Plan (incorporated by reference to FirstEnergy's Form 8-K filed February 25, 2011, Exhibit 10.4, File No. 21011).

(B) 10-25 Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-29 File No. 333-21011).

(B) 10-26 Amendment No. 1 to Allegheny Energy, Inc. Amended and Restated Revised Plan for Deferral of Compensation of Directors (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-30 File No. 333-21011).

10-27 Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein. (incorporated by reference to FE's Form 10-Q filed August 2, 2011, Exhibit 10.1, File No. 333-21011).

10-28 Amendment, dated as of May 8, 2012, to the Credit Agreement, dated as of June 17, 2011, among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE's Form 8-K filed May 11, 2012, Exhibit 10.2, File No. 333-21011).

10-29 Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 8-K filed May 13, 2013, Exhibit 10.1, File No. 333-21011).

10-30 Amendment, dated as of October 31, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 10-Q filed November 5, 2013, Exhibit 10.1(a), File No. 333-21011).

10-31 Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, May 8, 2013 and October 31, 2013, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, the Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE' s Form 8-K filed April 4, 2014, Exhibit 10.1, File No. 333-21011).

(B) 10-32 Employment Agreement between FirstEnergy Corp. and Anthony J. Alexander, dated March 20, 2012. (incorporated by reference to FE's Form 10-Q filed March 31, 2012, Exhibit 10.1, File No. 333-21011).

(B) 10-33 Form of Officer Indemnification Agreement (incorporated by reference to FirstEnergy's Form 8-K filed July 23, 2012, Exhibit 10.1, File No. 333-21011).

(B) 10-34 Amendment No.1 to the FirstEnergy Corp. Change in Control Severance Plan, amended and restated as of September 18, 2012 (incorporated by reference to FE's Form 10-Q filed November 8, 2012, Exhibit 10.1, File No. 333-21011).

10-35 U.S. $1,000,000,000 Credit Agreement, dated as of May 8, 2012, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed May 11, 2012, Exhibit 10.3, File No. 333-21011).

10-36 Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of May 8, 2012, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed May 13, 2013, Exhibit 10.3, File No. 333-21011).

10-37 Amendment, dated as of March 31, 2014 to the Credit Agreement, dated as of May 8, 2012, and as amended as of May 8, 2013, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10.3, File No. 333-21011).

10-38 Term Loan Credit Agreement, dated as of March 31, 2014, among FE, as borrower, the banks named therein and The Royal Bank of Scotland, plc, as administrative agent (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10.4, File No. 333-21011).

10-39 Guarantee, dated as of September 16, 2013 by FirstEnergy Corp. in favor of participants under the FirstEnergy Corp. Executive Deferred Compensation Plan (incorporated by reference to FE's Form 10-Q filed November 5, 2013, Exhibit 10.2, File No. 333-21011).

(B) 10-40 Executive Severance Benefits Plan (incorporated by reference to FE's Form 10-K filed February 27, 2014, Exhibit 10-44 File No. 333-21011).

(B) 10-41 Amendment No. 2 to the FirstEnergy Corp. Change in Control Severance Plan (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-44, File No. 333-21011).

(B) 10-42 Amendment No. 1 to the FirstEnergy Corp. Executive Deferred Compensation Plan, dated as of January 23, 2014 (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-45, File No. 333-21011).

(B) 10-43 Executive Short-Term Incentive Program (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-46, File No. 333-21011).

(B) 10-44 Form of 2015-2017 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-47, File No. 333-21011).

(B) 10-45 Form of 2015-2017 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-48, File No. 333-21011).

(B) 10-46 Form of Restricted Stock Agreement (incorporated by reference to FE's Form 10-K filed February 17, 2015, Exhibit 10-49, File No. 333-21011).

(B) 10-47 FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated July 20, 2015, and effective as of November 1, 2015 (incorporated by reference to FE's Form 8-K filed July 24, 2015, Exhibit 10.1, File No. 333-21011).

(B) 10-48	Performance-Earned Restricted Stock Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James F. Pearson (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-49	Performance-Earned Cash Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James H. Lash (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-50	FirstEnergy Corp. 2017 Change in Control Severance Plan, dated as of September 15, 2015, and effective as of January 1, 2017 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-51	Waiver of Participation in the FirstEnergy Corp. Change in Control Severance Plan, entered into by Charles E. Jones dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-52	Non-Competition and Non-Disparagement Agreement, dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.3, File No. 333-21011).
(B) 10-53	2015-2017 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement between FirstEnergy Corp. and Anthony J. Alexander, effective March 2, 2015 (incorporated by reference to FE's Form 10-Q filed May 1, 2015, Exhibit 10.1, File No. 333-21011).
(B) 10-54	2015-2017 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement between FirstEnergy Corp. and Anthony J. Alexander, effective March 2, 2015 (incorporated by reference to FE's Form 10-Q filed May 1, 2015, Exhibit 10.2, File No. 333-21011).
(B) 10-55	FirstEnergy Corp. 2015 Incentive Compensation Plan (incorporated by reference to FirstEnergy's Definitive Proxy Statement filed April 1, 2015, Appendix A, File No. 333-21011).
(A)(B) 10-56	Executive Short-Term Incentive Program, effective February 16, 2016.
(A)(B) 10-57	Form of 2016-2018 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A)(B) 10-58	Form of 2016-2018 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A)(B) 10-59	Form of 2016 Restricted Stock Award Agreement
(A) 12	Consolidated ratios of earnings to fixed charges.
(A) 21	List of Subsidiaries of the Registrant at December 31, 2015.
(A) 23	Consent of Independent Registered Public Accounting Firm.
(A) 31-1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 31-2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
101	The following materials from the Annual Report on Form 10-K for FirstEnergy Corp. for the period ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

† Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Registrant will furnish the omitted schedules to the Securities and Exchange Commission upon request by the Commission.

(A) Provided herein in electronic format as an exhibit.

(B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, FirstEnergy has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but hereby agrees to furnish to the SEC on request any such documents.

FES

Exhibit Number	
3-1	Articles of Incorporation of FirstEnergy Solutions Corp., as amended August 31, 2001. (incorporated by reference to FES' Form S-4 filed August 6, 2007, Exhibit 3.2, File No. 333-145140-01).
3-2	Amended and Restated Code of Regulations of FirstEnergy Solutions Corp. effective as of August 26, 2009 (incorporated by reference to FES' Form 8-K filed August 27, 2009, Exhibit 3.1, File No. 000-53742).
4-1	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 19, 2008, of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) to The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1, File No. 333-145140-01).
4-1 (a)	First Supplemental Indenture dated as of June 25, 2008 (including Form of First Mortgage Bonds, Guarantee Series A of 2008 due 2009 and Form of First Mortgage Bonds, Guarantee Series B of 2008 due 2009). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(a), File No. 333-145140-01).
4-1 (b)	Second Supplemental Indenture dated as of March 1, 2009 (including Form of First Mortgage Bonds, Guarantee Series A of 2009 due 2014 and Form of First Mortgage Bonds, Guarantee Series B of 2009 due 2023). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(b), File No. 333-145140-01).
4-1 (c)	Third Supplemental Indenture dated as of March 31, 2009 (including Form of First Mortgage Bonds, Collateral Series A of 2009 due 2011). (incorporated by reference to FES' 10-Q filed May 7, 2009, Exhibit 4.1(c), File No. 333-145140-01).
4-1 (d)	Fourth Supplemental Indenture, dated as of June 15, 2009 (including Form of First Mortgage Bonds, Guarantee Series C of 2009 due 2018, Form of First Mortgage Bonds, Guarantee Series D of 2009 due 2029, Form of First Mortgage Bonds, Guarantee Series E of 2009 due 2029, Form of First Mortgage Bonds, Collateral Series B of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series C of 2009 due 2011). (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.3, File No. 333-145140-01).
4-1 (e)	Fifth Supplemental Indenture, dated as of June 30, 2009 (including Form of First Mortgage Bonds, Guarantee Series F of 2009 due 2047, Form of First Mortgage Bonds, Guarantee Series G of 2009 due 2018 and Form of First Mortgage Bonds, Guarantee Series H of 2009 due 2018). (incorporated by reference to FES' Form 8-K filed July 6, 2009, Exhibit 4.2, File No. 333-145140-01).
4-1 (f)	Sixth Supplemental Indenture, dated as of December 1, 2009 (including Form of First Mortgage Bonds, Collateral Series D of 2009 due 2012) (incorporated by reference to FES' Form 8-K filed December 4, 2009, Exhibit 4.2, File No. 000-53742).
4-1 (g)	Seventh Supplemental Indenture dated as of February 14, 2012 (including Form of First Mortgage Bonds, Collateral Series D of 2009 due 2012) (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 4.1(g), File No. 000-53742).
4-2	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009, by and between FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.1, File No. 333-145140-01).
4-2 (a)	First Supplemental Indenture, dated as of June 15, 2009 (including Form of First Mortgage Bonds, Guarantee Series A of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series B of 2009 due 2011, Form of First Mortgage Bonds, Collateral Series A of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series B of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series C of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series D of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series E of 2009 due 2010, Form of First Mortgage Bonds, Collateral Series F of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series G of 2009 due 2011). (incorporated by reference to FES' Form 8-K filed June 19, 2009, Exhibit 4.2(i), File No. 333-145140-01).
4-2 (b)	Second Supplemental Indenture, dated as of June 30, 2009 (including Form of First Mortgage Bonds, Guarantee Series C of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series D of 2009 due 2033, Form of First Mortgage Bonds, Guarantee Series E of 2009 due 2033, Form of First Mortgage Bonds, Collateral Series H of 2009 due 2011, Form of First Mortgage Bonds, Collateral Series I of 2009 due 2011 and Form of First Mortgage Bonds, Collateral Series J of 2009 due 2010). (incorporated by reference to FES' Form 8-K filed July 6, 2009, Exhibit 4.1, File No. 333-145140-01).
4-2 (c)	Third Supplemental Indenture, dated as of December 1, 2009 (including Form of First Mortgage Bonds, Collateral Series K of 2009 due 2012). (incorporated by reference to FES' Form 8-K filed December 4, 2009, Exhibit 4.1, File No. 000-53742).
4-2 (d)	Fourth Supplemental Indenture, dated as of February 14, 2012 (including Form of First Mortgage Bonds, Collateral Series K of 2009 due 2012). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 4.2(d), File No. 000-53742).

4-3	Indenture, dated as of August 1, 2009, between FirstEnergy Solutions Corp. and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to FES' Form 8-K filed August 7, 2009, Exhibit 4.1, File No. 000-53742).
4-3 (a)	First Supplemental Indenture, dated as of August 1, 2009 (including Form of 4.80% Senior Notes due 2015, Form of 6.05% Senior Notes due 2021 and Form of 6.80% Senior Notes due 2039). (incorporated by reference to FES' Form 8-K filed August 7, 2009, Exhibit 4.2, File No. 000-53742).
10-1	Form of 6.85% Exchange Certificate due 2034. (incorporated by reference to FES' Form S-4 filed August 6, 2007, Exhibit 4.1, File No. 333-145140-01).
10-2	Guaranty of FirstEnergy Solutions Corp., dated as of July 1, 2007. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-9, File No. 333-21011).
10-3	Indenture of Trust, Open-End Mortgage and Security Agreement, dated as of July 1, 2007, between the applicable Lessor and The Bank of New York Trust Company, N.A., as Indenture Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-3, File No. 333-21011).
10-4	6.85% Lessor Note due 2034. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-3, File No. 333-21011).
10-5	Participation Agreement, dated as of June 26, 2007, among FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), as Lessee, FirstEnergy Solutions Corp., as Guarantor, the applicable Lessor, U.S. Bank Trust National Association, as Trust Company, the applicable Owner Participant, The Bank of New York Trust Company, N.A., as Indenture Trustee, and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-1, File No. 333-21011).
10-6	Trust Agreement, dated as of June 26, 2007, between the applicable Owner Participant and U.S. Bank Trust National Association, as Owner Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-2, File No. 333-21011).
10-7	Pass Through Trust Agreement, dated as of June 26, 2007, among FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), FirstEnergy Solutions Corp., and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-12, File No. 333-21011).
10-8	Bill of Sale and Transfer, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-5, File No. 333-21011).
10-9	Facility Lease Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-6, File No. 333-21011).
10-10	Site Lease, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-7, File No. 333-21011).
10-11	Site Sublease, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-8, File No. 333-21011).
10-12	Support Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and the applicable Lessor. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-10, File No. 333-21011).
10-13	Second Amendment to the Bruce Mansfield Units 1, 2, and 3 Operating Agreement, dated as of July 1, 2007, between FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), The Cleveland Electric Illuminating Company and The Toledo Edison Company. (incorporated by reference to FE's Form 8-K/A filed August 2, 2007, Exhibit 10-11, File No. 333-21011).
10-14	Guaranty, dated as of March 26, 2007, by FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) on behalf of FirstEnergy Solutions Corp. (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.39, File No. 333-145140-01).
10-15	Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.40, File No. 333-145140-01).
10-16	Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.41, File No. 333-145140-01).
10-17	Guaranty, dated as of March 26, 2007, by FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) on behalf of FirstEnergy Solutions Corp. (incorporated by reference to FES' Form S-4/A filed August 20, 2007, Exhibit 10.42, File No. 333-145140-01).

(B) 10-18 Form of Trust Indenture dated as of December 1, 2005 between Ohio Water Development Authority and JP Morgan Trust Company, as Trustee, related to issuance of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) pollution control revenue refunding bonds. (incorporated by reference to FE's Form 10-K filed March 2, 2006, Exhibit 10-59, File No. 333-21011).

(B) 10-19 Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.), dated as of December 1, 2005. (incorporated by reference to FE's Form 10-K filed March 2, 2006, Exhibit 10-63, File No. 333-21011).

(C) 10-20 Form of Trust Indenture dated as of April 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing pollution control revenue refunding bonds issued on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FE's Form 10-Q filed May 9, 2006, Exhibit 10-3, File No. 333-21011).

(C) 10-21 Form of Waste Water Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) dated as of April 1, 2006. (incorporated by reference to FE's Form 10-Q filed May 9, 2006, Exhibit 10-4, File No. 333-21011).

(D) 10-22 Form of Trust Indenture dated as of December 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing State of Ohio Pollution Control Revenue Refunding Bonds (FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.)) (FirstEnergy Nuclear Generation Project). (incorporated by reference to FE's Form 10-K filed February 28, 2007, Exhibit 10-77, File No. 333-21011).

(D) 10-23 Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) dated as of December 1, 2006. (incorporated by reference to FE's Form 10-K filed February 28, 2007, Exhibit 10-80, File No. 333-21011).

(B) 10-24 First Amendment to Loan Agreement, dated as of February 14, 2012, between the Ohio Water Development Authority, as issuer, and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Generation Corp.). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 10.1, File No. 000-53742).

(B) 10-25 First Amendment to Loan Agreement, dated as of February 14, 2012, between the Ohio Air Quality Development Authority, as issuer, and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.). (incorporated by reference to FES' Form 10-Q filed May 1, 2012, Exhibit 10.2, File No. 000-53742).

10-26 First Supplemental Trust Indenture, dated April 2, 2012, supplementing and amending that certain Trust Indenture dated as of April 1, 2006 between the Ohio Water Development Authority and The Bank of New York Mellon Trust Company, N.A. as Trustee securing pollution control revenue refunding bonds issued on behalf of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (FirstEnergy Generation Project), which trust indenture, as amended, is substantially similar to various other PCRB trust indentures of FirstEnergy Generation, LLC (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.1, File No. 000-53742).

10-27 First Amendment to Loan Agreement dated April 2, 2012, amending the Waste Water Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.), dated as of April 1, 2006, which loan agreement, as amended, is substantially similar to various other PCRB loan agreements of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.2, File No. 000-53742).

10-28 First Supplemental Trust Indenture, dated April 2, 2012, supplementing and amending that certain Trust Indenture dated as of December 1, 2006 between the Ohio Water Development Authority and The Bank of New York Mellon Trust Company, N.A., as Trustee securing State of Ohio Pollution Control Revenue Refunding Bonds (FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.)) (FirstEnergy Nuclear Generation Project), which trust indenture, as amended, is substantially similar to various other PCRB trust indentures of FirstEnergy Nuclear Generation, LLC (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.3, File No. 000-53742).

10-29 First Amendment to Loan Agreement dated April 2, 2012, amending the Waste Water Facilities and Solid Waste Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.), dated as of December 1, 2006, which loan agreement, as amended, is substantially similar to various other PCRB loan agreements of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.) (incorporated by reference to FES' Form 10-Q filed August 7, 2012, Exhibit 10.4, File No. 000-53742).

10-30 Credit Agreement, dated as of June 17, 2011, among FirstEnergy Solutions Corp., and Allegheny Energy Supply Company, LLC, as borrowers, JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein. (incorporated by reference to FES' Form 10-Q filed August 2, 2011, Exhibit 10.1, File No. 000-53742).

10-31 Amendment, dated as of May 8, 2012, to the Credit Agreement, dated as of June 17, 2011, among FirstEnergy Solutions Corp., and Allegheny Energy Supply Company, LLC, as borrowers, JP Morgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed May 11, 2012, Exhibit 10.3, File No. 000-53742).

10-32	Amendment, dated as of May 8, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011 and May 8, 2012, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed May 13, 2013, Exhibit 10.2, File No. 000-53742).
10-33	Amendment, dated as of October 31, 2013, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011 and May 8, 2012 and May 8, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 10-Q filed November 5, 2013, Exhibit 10.1(b), File No. 000-53742).
10-34	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011, May 8, 2012 and May 8, 2013 and October 31, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES' Form 8-K filed April 4, 2014, Exhibit 10.2, File No. 000-53742).
(A) 31-1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 31-2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
101	The following materials from the Annual Report on Form 10-K for FirstEnergy Solutions Corp. for the period ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
(A)	Provided herein in electronic format as an exhibit.
(B)	Four substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to four other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, the Ohio Air Quality Authority and Beaver County Industrial Development Authority, Pennsylvania, relating to pollution control notes of FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).
(C)	Three substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to three other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority and the Beaver County Industrial Development Authority relating to pollution control notes of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).
(D)	Seven substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to one other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, three other series of pollution control bonds issued by the Ohio Air Quality Development Authority and the three other series of pollution control bonds issued by the Beaver County Industrial Development Authority, relating to pollution control notes of FirstEnergy Generation, LLC (f/k/a FirstEnergy Generation Corp.) and FirstEnergy Nuclear Generation, LLC (f/k/a FirstEnergy Nuclear Generation Corp.).

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, FES has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but hereby agrees to furnish to the SEC on request any such documents.

FIRSTENERGY CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31				
	2011	2012	2013	2014	2015
	(Dollars in millions)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income from continuing operations	$ 856	$ 755	$ 375	$ 213	$ 578
Interest and other charges, before reduction for amounts capitalized and deferred	1,008	1,001	1,016	1,073	1,132
Capitalized interest	(70)	(72)	(75)	(69)	(68)
Provision for income taxes (benefits)	566	545	195	(42)	315
Interest element of rentals charged to income (1)	150	136	96	83	78
Earnings as defined	$ 2,510	$ 2,365	$ 1,607	$ 1,258	$ 2,035
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	$ 1,008	$ 1,001	$ 1,016	$ 1,073	$ 1,132
Interest element of rentals charged to income (1)	150	136	96	83	78
Fixed charges as defined	$ 1,158	$ 1,137	$ 1,112	$ 1,156	$ 1,210
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.17	2.08	1.45	1.09	1.68

(1) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

FIRSTENERGY CORP.
LIST OF SUBSIDIARIES OF THE REGISTRANT
AT DECEMBER 31, 2015

FirstEnergy Nuclear Operating Company - Incorporated in Ohio

FirstEnergy Service Company - Incorporated in Ohio

FirstEnergy Solutions Corp. - Incorporated in Ohio

FirstEnergy Transmission, LLC - Organized in Delaware

FirstEnergy Ventures Corp. - Incorporated in Ohio

Jersey Central Power & Light Company - Incorporated in New Jersey

Metropolitan Edison Company - Incorporated in Pennsylvania

Monongahela Power Company - Incorporated in Ohio

Ohio Edison Company - Incorporated in Ohio

Pennsylvania Electric Company - Incorporated in Pennsylvania

The Cleveland Electric Illuminating Company - Incorporated in Ohio

The Potomac Edison Company - Incorporated in Maryland

The Toledo Edison Company - Incorporated in Ohio

West Penn Power Company - Incorporated in Pennsylvania

FirstEnergy Corp.

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-204422, 333-191382, and 333-48587), and Form S-8 (Nos. 333-202184, 333-204436, 333-56094, 333-72768, 333-81183, 333-89356, 333-101472, 333-110662, 333-146170, 333-165640, and 333-172464) of FirstEnergy Corp. of our report dated February 16, 2016, relating to the financial statements, financial statement schedule, and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2016

Met-Ed Exhibit JD-15
EXHIBIT 31.1
Attachment A
Witness: J. Dipre

Certification

I, Charles E. Jones, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2016

/s/ Charles E. Jones

Charles E. Jones
President and Chief Executive Officer

Certification

I, Donald R. Schneider, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Solutions Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2016

/s/ Donald R. Schneider

Donald R. Schneider
President

Certification

I, James F. Pearson, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2016

/s/ James F. Pearson

James F. Pearson
Executive Vice President and
Chief Financial Officer

Certification

I, James F. Pearson, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Solutions Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 16, 2016

/s/ James F. Pearson

James F. Pearson
Executive Vice President and
Chief Financial Officer

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Corp. ("Company") on Form 10-K for the period ending December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles E. Jones

Charles E. Jones
President and Chief Executive Officer

/s/ James F. Pearson

James F. Pearson
Chief Financial Officer

Date: February 16, 2016

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Solutions Corp. ("Company") on Form 10-K for the period ending December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Donald R. Schneider

Donald R. Schneider
President
(Chief Executive Officer)

/s/ James F. Pearson

James F. Pearson
Chief Financial Officer

Date: February 16, 2016

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-4:

"Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates – system structure."

RESPONSE:

See Met-Ed Exhibit JD-16 Attachment A and Met-Ed Exhibit JD-16 Attachment B.

Corporate Summary Report

12/28/15

ME Exhibit JD-16
Attachment A
Witness: J. Dipre

Metropolitan Edison Company

Entity Vitals

Company Name	Metropolitan Edison Company
Domestic Jurisdiction	Pennsylvania
Formation Date	08-24-1917
Federal Tax ID	23-0870160
Charter ID	229978
Business Purpose	An electric utility company.

Entity Addresses

Address	2800 Pottsville Pike, Reading, Pennsylvania 19605-2459

Authority to do Business

Jurisdiction	New Jersey
Qualified Date	06-13-1988

Management Structure

DIRECTORS

Name	Title
Jones, Charles E.	Director
Pearson, James F.	Director
Strah, Steven E.	Director

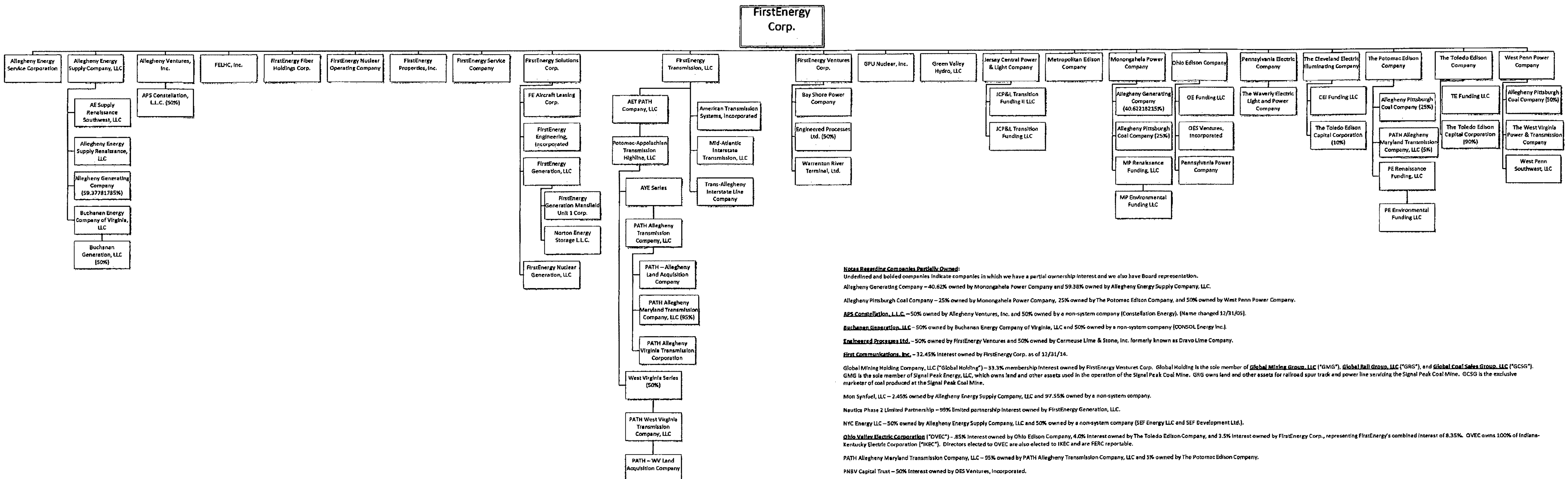
OFFICERS

Name	Title
Strah, Steven E.	President
Pearson, James F.	Executive Vice President and Chief Financial Officer
Vespoli, Leila L.	Executive Vice President, Markets and Chief Legal Officer
Ferguson, Rhonda S.	Vice President and Corporate Secretary
Garanich, James G.	Vice President, Tax
Moss, Linda L.	Vice President
Reffner, Robert P.	Vice President and General Counsel
Staub, Steven R.	Vice President and Treasurer
Taylor, K. Jon	Vice President and Controller
Barwood, Marlene A.	Assistant Controller
Lisowski, Jason J.	Assistant Controller
Petrik, Jason S.	Assistant Controller
Dunlap, Daniel M.	Assistant Corporate Secretary
Geyer, Jennifer L.	Assistant Corporate Secretary
Shuttleworth, Edward L.	Regional President

Ownership Holdings

There are no entries in this list

ME Exhibit JD-16
Attachment B
Witness: J. Dirpe



Notes Regarding Companies Partially Owned:
Underlined and bolded companies indicate companies in which we have a partial ownership interest and we also have Board representation.

Allegheny Generating Company – 40.62% owned by Monongahela Power Company and 59.38% owned by Allegheny Energy Supply Company, LLC.

Allegheny Pittsburgh Coal Company – 25% owned by Monongahela Power Company, 25% owned by The Potomac Edison Company, and 50% owned by West Penn Power Company.

APS Constellation, L.L.C. – 50% owned by Allegheny Ventures, Inc. and 50% owned by a non-system company (Constellation Energy). (Name changed 12/31/05).

Buchanan Generation, LLC – 50% owned by Buchanan Energy Company of Virginia, LLC and 50% owned by a non-system company (CONSOL Energy Inc.).

Engineered Processes Ltd. – 50% owned by FirstEnergy Ventures and 50% owned by Carmeuse Lime & Stone, Inc. formerly known as Dravo Lime Company.

First Communications, Inc. – 32.45% interest owned by FirstEnergy Corp. as of 12/31/14.

Global Mining Holding Company, LLC ("Global Holding") – 33.3% membership interest owned by FirstEnergy Ventures Corp. Global Holding is the sole member of **Global Mining Group, LLC** ("GMG"), **Global Rail Group, LLC** ("GRG"), and **Global Coal Sales Group, LLC** ("GCSG"). GMG is the sole member of Signal Peak Energy, LLC, which owns land and other assets used in the operation of the Signal Peak Coal Mine. GRG owns land and other assets for railroad spur track and power line servicing the Signal Peak Coal Mine. GCSG is the exclusive marketer of coal produced at the Signal Peak Coal Mine.

Mon Synfuel, LLC – 2.45% owned by Allegheny Energy Supply Company, LLC and 97.55% owned by a non-system company.

Nautica Phase 2 Limited Partnership – 99% limited partnership interest owned by FirstEnergy Generation, LLC.

NYC Energy LLC – 50% owned by Allegheny Energy Supply Company, LLC and 50% owned by a non-system company (SEF Energy LLC and SEF Development Ltd.).

Ohio Valley Electric Corporation ("OVEC") - .85% interest owned by Ohio Edison Company, 4.0% interest owned by The Toledo Edison Company, and 3.5% interest owned by FirstEnergy Corp., representing FirstEnergy's combined interest of 8.35%. OVEC owns 100% of Indiana-Kentucky Electric Corporation ("IKEC"). Directors elected to OVEC are also elected to IKEC and are FERC reportable.

PATH Allegheny Maryland Transmission Company, LLC – 95% owned by PATH Allegheny Transmission Company, LLC and 5% owned by The Potomac Edison Company.

PNBV Capital Trust – 50% interest owned by OES Ventures, Incorporated.

Potomac-Appalachian Transmission Highline, LLC – West Virginia Series – 50% owned by AET PATH Company, LLC and 50% owned by AEP Transmission Holding Company, LLC.

Shippingport Capital Trust – 6.55106% interest owned by The Toledo Edison Capital Corporation as of 10/13/08.

The Toledo Edison Capital Corporation – 90% interest owned by The Toledo Edison Company and 10% owned by The Cleveland Electric Illuminating Company.

Utility Associates, Inc. – 6.19% owned by Allegheny Ventures, Inc. and 93.81% owned by non-system individuals.

01-15-16

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-1:

"The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists."

RESPONSE:

See Met-Ed Exhibit JD-17 Attachments A and B.

METROPOLITAN EDISON COMPANY

FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2015 AND 2014

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in these financial statements to identify Metropolitan Edison Company and its current and former affiliated companies:

ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FE	FirstEnergy Corp., a public utility holding company
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI and TrAIL and has a joint venture in PATH
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
PE	The Potomac Edison Company, a Maryland and West Virginia electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

The following abbreviations and acronyms are used to identify frequently used terms in these financial statements:

AFS	Available-for-sale
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ALJ	Administrative Law Judge
ASU	Accounting Standards Update
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GAAP	Accounting Principles Generally Accepted in the United States of America
ICE	IntercontinentalExchange, Inc.
IRS	Internal Revenue Service

GLOSSARY OF TERMS, *Continued*

kV	Kilovolt
LTIIPs	Long-Term Infrastructure Improvement Plans
MLP	Master Limited Partnership
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOL	Net Operating Loss
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPUC	Pennsylvania Public Utility Commission
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RTEP	Regional Transmission Expansion Plan
SEC	United States Securities and Exchange Commission
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SREC	Solar Renewable Energy Credit
TMI-2	Three Mile Island Unit 2
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VIE	Variable Interest Entity

Independent Auditor's Report

To Management and the Board of Directors
Of Metropolitan Edison Company

In our opinion, the accompanying balance sheets and the related statements of income and comprehensive income, of common stockholder's equity, and of cash flows present fairly, in all material respects, the financial position of Metropolitan Edison Company at December 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Cleveland, Ohio
February 29, 2016

METROPOLITAN EDISON COMPANY
STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2015	2014
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 820	$ 757
Gross receipts tax collections	47	41
Total revenues	867	798
OPERATING EXPENSES:		
Purchased power from affiliates	77	149
Purchased power from non-affiliates	285	202
Other operating expenses	167	169
Pension and OPEB mark-to-market adjustment	25	57
Provision for depreciation	52	53
Amortization of regulatory assets, net	45	1
General taxes	54	48
Total operating expenses	705	679
OPERATING INCOME	162	119
OTHER INCOME (EXPENSE):		
Miscellaneous income	4	4
Interest expense	(51)	(51)
Capitalized interest	1	1
Total other expense	(46)	(46)
INCOME BEFORE INCOME TAXES	116	73
INCOME TAXES	49	27
NET INCOME	$ 67	$ 46
STATEMENTS OF COMPREHENSIVE INCOME		
NET INCOME	$ 67	$ 46
OTHER COMPREHENSIVE LOSS:		
Pension and OPEB prior service costs	(10)	—
Other comprehensive loss	(10)	—
Income tax benefits on other comprehensive loss	(4)	—
Other comprehensive loss, net of tax	(6)	—
COMPREHENSIVE INCOME	$ 61	$ 46

The accompanying Notes to Financial Statements are an integral part of these financial statements.

Met-Ed Exhibit JD-17
Attachment A
Witness: J. Dipre

METROPOLITAN EDISON COMPANY
BALANCE SHEETS

(In millions, except share amounts)	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $8 in 2015 and $7 in 2014	$ 135	$ 127
Affiliated companies	25	26
Other	12	17
Prepaid taxes	6	6
Other	3	4
	181	180
UTILITY PLANT:		
In service	2,789	2,745
Less — Accumulated provision for depreciation	950	925
	1,839	1,820
Construction work in progress	67	83
	1,906	1,903
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	325	337
Other	1	1
	326	338
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416	416
Regulatory assets	77	36
Other	13	16
	506	468
	$ 2,919	$ 2,889
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 3	$ 3
Short-term borrowings-		
Affiliated companies	54	33
Accounts payable-		
Affiliated companies	8	25
Other	54	44
Accrued taxes	10	15
Accrued interest	16	20
Other	55	62
	200	202
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 900,000 shares -740,905 shares outstanding	790	804
Accumulated other comprehensive income	8	14
Accumulated deficit	(1)	(23)
Total common stockholder's equity	797	795
Long-term debt and other long-term obligations	863	866
	1,660	1,661
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	520	502
Nuclear fuel disposal costs	45	45
Asset retirement obligations	199	187
Retirement benefits	137	129
Power purchase contract liability	10	18
Other	148	145
	1,059	1,026
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
	$ 2,919	$ 2,889

The accompanying Notes to Financial Statements are an integral part of these financial statements.

METROPOLITAN EDISON COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock						
(In millions, except share amounts)	**Number of Shares**		**Carrying Value**		**Accumulated Other Comprehensive Income**		**Accumulated Deficit**
Balance, January 1, 2014	740,905	$	828	$	14	$	(44)
Net Income							46
Stock based compensation			1				
Return of capital to parent			(25)				
Cash dividends on common stock							(25)
Balance, December 31, 2014	740,905	$	804	$	14	$	(23)
Net Income							67
Pension and OPEB, net of $4 of income tax benefits (Note 3)					(6)		
Stock based compensation			1				
Return of capital to parent			(15)				
Cash dividends on common stock							(45)
Balance, December 31, 2015	740,905	$	790	$	8	$	(1)

The accompanying Notes to Financial Statements are an integral part of these financial statements.

METROPOLITAN EDISON COMPANY
STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 67	$ 46
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	52	53
Asset removal costs charged to income	11	6
Amortization of other regulatory assets, net	45	1
Deferred purchased power and other costs	(14)	(6)
Deferred income taxes and investment tax credits, net	23	(5)
Retirement benefits	(12)	(14)
Pension and OPEB mark-to-market adjustment	25	57
Pension trust contribution	(23)	—
Nuclear decommissioning trust income	13	12
Changes in current assets and liabilities-		
Receivables	1	11
Accounts payable	(7)	(10)
Accrued taxes	(5)	(11)
Accrued interest	(4)	4
Cash collateral, net	(6)	5
Other	7	16
Net cash provided from operating activities	173	165
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	—	250
Short-term borrowings, net	21	—
Redemptions and repayments-		
Long-term debt	—	(179)
Short-term borrowings, net	—	(40)
Common stock dividend payments	(45)	(25)
Return of capital payments	(15)	(25)
Other	(4)	(4)
Net cash used for financing activities	(43)	(23)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(106)	(125)
Sales of investment securities held in trusts	245	334
Purchases of investment securities held in trusts	(258)	(346)
Asset removal costs	(11)	(6)
Other	—	1
Net cash used for investing activities	(130)	(142)
Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	—	—
Cash and cash equivalents at end of period	$ —	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid during the year-		
Interest (net of amounts capitalized)	$ 52	$ 44
Income taxes, net of refunds	$ 37	$ 37

The accompanying Notes to Financial Statements are an integral part of these financial statements.

METROPOLITAN EDISON COMPANY
NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

ME is a wholly owned subsidiary of FE, and is incorporated in Pennsylvania. ME operates an electric transmission and distribution system in Pennsylvania. ME is subject to regulation by the PPUC and the FERC.

The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. ME has evaluated events and transactions for potential recognition or disclosure through February 29, 2016, the issuance date of the financial statements.

Certain prior year amounts have been reclassified to conform to the current year presentation.

REVENUES AND RECEIVABLES

Receivables represent amounts due from retail and wholesale sales to customers. There was no material concentration of receivables as of December 31, 2015 and 2014, with respect to any particular segment of ME's customers. Billed and unbilled customer receivables were $97 million and $38 million, respectively, as of December 31, 2015 and $84 million and $43 million, respectively, as of December 31, 2014.

ACCOUNTING FOR THE EFFECTS OF REGULATION

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. ME nets its regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In thousands)	
Regulatory transition costs	$ 4	$ 2	$ 2
Customer receivables for future income taxes	91	93	(2)
Nuclear decommissioning and spent fuel disposal costs	(121)	(145)	24
Asset removal costs	1	—	1
Deferred transmission costs	18	38	(20)
Deferred generation costs	(18)	(18)	—
Deferred distribution costs	50	—	50
Contract valuations	10	18	(8)
Storm-related costs	54	66	(12)
Other	(12)	(18)	6
Net Regulatory assets included in Consolidated Balance Sheets	$ 77	$ 36	$ 41

Regulatory assets that do not earn a current return totaled approximately $62 million and $69 million as of December 31, 2015, and 2014, respectively, primarily related to storm damage costs. Effective with the approved settlement on April 9, 2015, associated with its general base rate case, ME transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. ME recognizes liabilities for planned major maintenance projects as they are incurred.

ME provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. Depreciation expense was approximately 1.9% of average depreciable property in 2015 and 2014.

ME reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. ME utilizes the income approach, based upon discounted cash flows to estimate fair value.

GOODWILL

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. ME evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, ME assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that its fair value is less than its carrying value (including goodwill). If ME concludes that it is not more likely than not that its fair value is less than its carrying value, then no further testing is required. However, if ME concludes that it is more likely than not that its fair value is less than its carrying value or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

No impairment of goodwill was indicated as a result of testing in 2015 and 2014. In 2015, ME performed a qualitative assessment, assessing economic, industry and market considerations in addition to ME's overall financial performance. It was determined that the fair value was, more likely than not, greater than its carrying value and a quantitative analysis was not necessary.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. ME is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. ME does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, ME debt issuance costs included in Deferred Charges and Other Assets were $4 million. ME will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, ME reclassified $12 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. ME is currently evaluating the impact on its financial statements of adopting this standard.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, for the years ended December 31, 2015 and 2014 for ME are shown in the following tables:

(In millions)	Defined Benefit Pension & OPEB Plans
AOCI Balance, January 1, 2014	$ 14
Other comprehensive income before reclassifications	14
Amounts reclassified from AOCI	(14)
Other comprehensive loss	—
Income tax benefit on other comprehensive loss	—
Other comprehensive loss, net of tax	—
AOCI Balance, December 31, 2014	$ 14
Amounts reclassified from AOCI	(10)
Other comprehensive loss	(10)
Income tax benefits on other comprehensive loss	(4)
Other comprehensive loss, net of tax	(6)
AOCI Balance, December 31, 2015	$ 8

The following amounts were reclassified from AOCI for ME in the years ended December 31, 2015 and 2014:

Reclassifications out of AOCI [2]	Amount Reclassified from AOCI 2015	2014	Affected Line Item in the Statement of Net Income
	(in millions)		
Defined Benefit Pension and OPEB Plans			
Prior-service costs	$ (10)	$ (14)	[1]
	4	6	Income taxes
	$ (6)	$ (8)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees, including employees of ME. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. ME recognizes its allocated portion of the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. ME also recognized its allocated portion of obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. In 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Payment of benefits for participants that elected an immediate lump sum cash payment or an annuity resulted in a $40 million reduction to the underfunded status of the pension plan. Additionally, during 2015 and 2014, certain unions ratified their labor agreements that ended subsidized retiree health care resulting in a reduction to the OPEB benefit obligation by approximately $10 million and $97 million, respectively. ME's share of the net liability reductions was approximately $13 million in 2014 and there was no reduction to ME's net liability in 2015.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. ME's pension and OPEB mark-to-market adjustment for the years ended December 31, 2015 and 2014 were $44 million ($25 million net of amounts capitalized) and $95 million ($57 million net of amounts capitalized), respectively. In 2015, the pension and OPEB mark-to-market adjustment primarily reflects lower than expected asset returns as well as the impact of other demographic assumptions including revisions to the mortality assumptions partially offset by a 25 basis point increase in the discount rate.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million ($23 million from ME) to its qualified pension plan. In 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan with $160 million contributed to date. Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million, or (2.7)% compared to earnings of $387 million, or 6.2% in 2014, and assumed a 7.75% rate of return for each year on plan assets which generated $476 million and $496 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans.

The following is a summary of the plan status:

As of December 31,	Pension 2015	Pension 2014	OPEB 2015	OPEB 2014
	(in millions)			
FE benefit obligation	$ 9,079	$ 9,249	$ 724	$ 757
FE fair value of plan assets	5,338	5,824	431	464
FE funded status	(3,741)	(3,425)	(293)	(293)
FE accumulated benefit obligation	8,579	8,744	—	—
FE net periodic costs (credits) (1)	485	1,350	(108)	(154)
ME's share of net liability	114	106	23	23
ME's share of net periodic costs (credits) (1)	31	71	(8)	(12)

(1) Includes annual pension and OPEB mark-to-market adjustment

As of December 31,	Pension 2015	Pension 2014	OPEB 2015	OPEB 2014
Assumptions Used to Determine Benefit Obligations				
(as of December 31)				
Discount rate	4.50%	4.25%	4.25%	4.00%
Rate of compensation increase	4.20%	4.20%	N/A	N/A
Assumed Health Care Cost Trend Rates				
(as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	7.0-7.5%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.50%	4.50%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	N/A	N/A	2026	2026
Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31				
Weighted-average discount rate	4.25%	5.00%	4.00%	4.75%
Expected long-term return on plan assets	7.75%	7.75%	7.75%	7.75%
Rate of compensation increase	4.20%	4.20%	N/A	N/A

In selecting an assumed discount rate, FE considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed rates of return on plan assets consider historical market returns and economic forecasts for the types of investments held by FE's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

4. TAXES

ME records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

ME is party to an intercompany income tax allocation agreement with FE and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from FE's merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

On December 18, 2015, the President signed into law the Protecting Americans from Tax Hikes Act of 2015 (the Act). The Act, among other things, made permanent the R&D tax credit, and also extended accelerated depreciation of qualified capital investments placed into service. This bonus depreciation provision is 50% for qualifying assets placed into service from 2015 through 2017, 40% for qualifying assets placed into service in 2018 and 30% for qualifying assets placed into service in 2019. ME recorded the effects of the Act that apply to 2015 in the fourth quarter of 2015. The extension of the tax benefits did not have a significant impact to the effective tax rate.

INCOME TAXES:	**2015**	**2014**
	(In millions)	
Currently payable-		
Federal	$ 16	$ 24
State	10	8
	26	32
Deferred, net-		
Federal	24	2
State	(1)	(7)
	23	(5)
Total income taxes	$ 49	$ 27

ME's tax rates are affected by permanent items as well as discrete items that may occur in any given period, but are not consistent from period to period. The following table provides a reconciliation of federal income tax expense at the federal statutory rate to the total income taxes for the years ended December 31:

(In millions)	**2015**	**2014**
Book income before income taxes	$ 116	$ 73
Federal income tax expense at statutory rate (35%)	$ 41	$ 25
Increases (reductions) in taxes resulting from-		
State income taxes, net of federal tax benefit	7	5
Change in accounting method	—	(6)
Other, net	1	3
Total income taxes	$ 49	$ 27
Effective income tax rate	42.2%	37.0%

In 2015, ME's effective tax rate was 42.2% compared to 37.0% in 2014. The increase in the effective tax rate resulted from the absence of a tax benefit recognized in 2014 associated with an IRS approved change in accounting method for costs associated with the refurbishment of meters and transformers.

Accumulated deferred income taxes as of December 31, 2015 and 2014 were as follows:

(In millions)	**2015**	**2014**
Property basis differences	$ 673	$ 635
Net regulatory assets	99	126
Pension and OPEB	(96)	(90)
Nuclear decommissioning activities	(19)	(37)
Loss carryforwards and AMT credits	(28)	(30)
Asset retirement obligations	(82)	(78)
All other	(27)	(24)
Net deferred income tax liabilities	$ 520	$ 502

ME has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2015, the deferred income tax assets of ME, before any valuation allowances, consisted of $23 million, net of tax, of federal NOL carryforwards that begin to expire in 2031, and $6 million, net of tax, of state NOL carryforwards that begin to expire in 2029. Based on current judgment, it is anticipated that ME will fully utilize all NOLs within the applicable statutory time frames. However, ultimate utilization of NOLs may be impacted by many factors, including changes in statutory rates or other state law limitations on the use of NOLs, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state tax jurisdictions.

ME accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. For the years ended December 31, 2015 and 2014, ME did not record any unrecognized tax benefits, nor does ME have a reserve for any uncertain tax positions.

ME recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. During 2015 and 2014, ME did not record any interest related to uncertain tax positions.

For federal income tax purposes, ME files as a member of the FE consolidated group. In January 2015, the IRS completed its examination of FE's 2013 federal income tax return and issued a Revenue Agent Report, which did not result in a material impact to ME's effective tax rate. Tax year 2014 is currently under review by the IRS. ME has tax returns under review by state taxing authorities at the audit or appeals level for tax years 2009-2013.

General Taxes

Details of general taxes for the years ended December 31, 2015 and 2014 are shown below:

(In millions)	**2015**	**2014**
Gross receipts	$ 47	$ 41
Real and personal property	3	2
Social security and unemployment	5	5
Other	(1)	—
Total general taxes	$ 54	$ 48

5. LEASES

ME leases certain office space and other property and equipment under cancelable and noncancelable leases.

Operating lease expense which includes rent expense for the use of office space and other property and equipment primarily owned by affiliated companies for the years ended December 31, 2015 and 2014 was $4 million, respectively. ME's estimated future minimum lease payments for capital and operating leases as of December 31, 2015 with initial or remaining lease terms in excess of one year are as follows:

(In millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**	**Less: amount representing interest and fees**	**Present value of net minimum capital lease payments**
Capital leases	$ 4	$ 3	$ 3	$ 3	$ 2	$ 4	$ 19	$ 2	$ 17
Operating leases	$ 3	$ 3	$ 5	$ —	$ 2	$ 25	$ 38	N/A	N/A

The carrying amounts of assets recorded under capital lease agreements included in "Property, plant and equipment, net" on ME's Balance Sheets as of December 31, 2015 and 2014 were $17 million and $24 million, respectively.

6. FAIR VALUE MEASUREMENTS

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include AFS securities.

At the end of each reporting period, ME evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. ME first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, ME considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Generally, unrealized gains and losses on AFS securities are recognized in AOCI. However, the NDT is subject to regulatory accounting. Therefore, net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities is expected to be recovered from or refunded to customers.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

ME holds debt and equity securities within its NDT trust. These trust investments are considered AFS securities recognized at fair market value. ME has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT trusts as of December 31, 2015 and December 31, 2014:

	December 31, 2015[(1)]			December 31, 2014[(1)]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities	$ 246	$ 1	$ 247	$ 244	$ 3	$ 247
Equity securities	$ 68	$ 4	$ 72	$ 72	$ 10	$ 82

(1) Excludes short-term cash investments of $6 million and $8 million as of December 31, 2015 and December 31, 2014, respectively.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales and interest and dividend income for the years ended December 31, 2015 and 2014 were as follows:

	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
2015	$ 245	$ 15	$ (17)	$ 13
2014	334	9	(6)	12

RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques for Level 2 and Level 3 are as follows:

Level 1 - Quoted prices for identical instruments in active markets.

Level 2 - Quoted prices for similar instruments in active markets;

- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data.

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement.

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee (see Note 7, Derivative Instruments), are used to measure fair value. A more detailed description of ME's valuation process for NUG contracts follows:

NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value using a mark-to-model methodology on a quarterly basis, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWHs. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

ME primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, ME maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2015 from those used as of December 31, 2014. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2015 and 2014. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

Recurring Fair Value Measurements	**December 31, 2015**				**December 31, 2014**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				***(In millions)***				
Corporate debt securities	$ —	$ 225	$ —	$ 225	$ —	$ 227	$ —	$ 227
Equity securities(1)	72	—	—	72	82	—	—	82
Foreign government debt securities	—	9	—	9	—	9	—	9
U.S. government debt securities	—	12	—	12	—	11	—	11
Other(2)	—	4	—	4	—	9	—	9
Total assets	72	250	—	322	82	256	—	338
Liabilities								
Derivative liabilities - NUG contracts(3)	—	—	(10)	(10)	—	—	(18)	(18)
Total liabilities	—	—	(10)	(10)	—	—	(18)	(18)
Net assets (liabilities)(4)	$ 72	$ 250	$ (10)	$ 312	$ 82	$ 256	$ (18)	$ 320

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.
(2) Primarily consists of short-term cash investments.
(3) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.
(4) Excludes $3 million and $(1) million as of December 31, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUGs held by ME and classified as Level 3 in the fair value hierarchy during the periods ended December 31, 2015 and December 31, 2014:

(In millions)	**Derivative Liability NUG Contracts[1]**
January 1, 2014 Balance	$ (28)
Unrealized gain	4
Settlements	6
December 31, 2014 Balance	(18)
Unrealized loss	(6)
Settlements	14
December 31, 2015 Balance	$ (10)

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

Level 3 Quantitative Information

The following table provides quantitative information for NUG contracts held by ME that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2015:

	Fair Value, Net (In millions)	**Valuation Technique**	**Significant Input**	**Range**	**Weighted Average**	**Units**
NUG Contracts	$ (10)	Model	Generation Regional electricity prices	2,449 to 219,600 $38.37 to $45.88	48,412 $42.13	MWH Dollars/MWH

LONG-TERM DEBT

The following table provides the approximate fair value and related carrying amounts of long-term debt, excluding capital lease obligations and net unamortized premiums and discounts as of December 31, 2015 and December 31, 2014.

	December 31, 2015		**December 31, 2014**	
(In millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	$ 850	$ 883	$ 850	$ 908

The fair values of long-term debt reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of ME. ME classified long-term debt as Level 2 in the fair value hierarchy as of December 31, 2015 and December 31, 2014.

7. DERIVATIVE INSTRUMENTS

ME is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy, including ME. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice.

NUG contracts are reflected on the Balance Sheets at fair value on a gross basis with changes in fair value recorded as regulatory assets and liabilities. The portfolio of NUG contracts does not allow for the offsetting of derivative assets and derivative liabilities. ME held no other derivative assets or liabilities as of December 31, 2015 or December 31, 2014. ME performs qualitative analyses to determine whether a variable interest gives ME a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 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. None of the NUG contracts qualify as a VIE.

ME had NUG liabilities of $10 million and $18 million in power purchase contract liabilities on its Balance Sheets as of December 31, 2015 and December 31, 2014 respectively. None of the counterparties to these contracts require collateral to mitigate credit exposure. ME will purchase less than 1 million MWHs of power associated with its NUG contracts in future periods.

Unrealized gains (losses) on ME's NUG contracts for the years ended December 31, 2015 and 2014 were $(6) million and $4 million, respectively, which are subject to regulatory accounting and do not impact earnings.

8. CAPITALIZATION

COMMON STOCK

In addition to paying dividends from retained earnings, ME has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its FERC-defined equity to total capitalization ratio (without consideration of retained earnings) remains above 35%.

PREFERRED STOCK

ME is authorized to issue 10,000,000 shares preferred stock with no par value as of December 31, 2015. As of December 31, 2015, and 2014, there were no preferred shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for ME as of December 31, 2015 and 2014:

	As of December 31, 2015		As of December 31,	
(Dollar amounts in millions)	**Maturity Date**	**Interest Rate**	**2015**	**2014**
Unsecured notes - fixed rate	2019 - 2025	3.50% - 7.70%	$ 850	$ 850
Capital lease obligations			17	20
Unamortized debt discounts			(1)	(1)
Currently payable long-term debt			(3)	(3)
Total long-term debt and other long-term obligations			$ 863	$ 866

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases and unamortized debt discounts and premiums, for the next five years as of December 31, 2015.

Year	**ME**
	(In millions)
2016	$ —
2017	—
2018	—
2019	300
2020	—

Debt Covenant Default Provisions

ME has various debt covenants under certain financing arrangements, including its revolving credit facility. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by ME to comply with the covenants contained in any of its financing arrangements could result in an event of default, which may have an adverse effect on ME's financial condition.

Additionally, there are cross-default provisions in certain financing arrangements of FE and its subsidiaries, including ME. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by ME would generally cross-default to FE financing arrangements containing these provisions, defaults by FE would generally not cross-default applicable ME financing arrangements.

As of December 31, 2015, ME was in compliance with all debt covenant default provisions.

9. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

ME had $54 million and $33 million of outstanding short-term borrowings as of December 31, 2015 and 2014, respectively.

Revolving Credit Facility

FirstEnergy Facility

FE and certain of its utility subsidiaries, including ME, participate in three five-year syndicated revolving credit facilities with aggregate commitments of $3.5 billion (Facility). On March 31, 2014, FE and certain of its utility subsidiaries, including ME, entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. The Facility was extended until March 31, 2019. The Facility was amended to increase the lending banks' commitments under the facility by $1.0 billion to a total of $3.5 billion and to increase the individual borrower sublimit for the Facility by $1.0 billion to a total of $3.5 billion.

Generally, borrowings under the Facility are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. The Facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of January 31, 2016, FE and the Utilities had available liquidity under the facility of $1.6 billion in the aggregate. Under this Facility, ME may borrow up to its sub-limit of $300 million, all of which was available to ME as of January 31, 2016. ME has regulatory and other short-term debt limitations of $500 million which includes amounts that may be borrowed under the regulated companies' money pool.

Subject to each borrower's sub-limit, $600 million of the Facility is available for the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the Facility and against the applicable borrower's borrowing sub-limit. As of January 31, 2016, there were no LOCs outstanding for the benefit of ME.

The Facility does not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facility is related to the credit ratings of the company borrowing the funds. Additionally, borrowings under the Facility are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

FirstEnergy Money Pool

FE's regulated companies, including ME, also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FE and the respective regulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreement must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the regulated pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2015 was 0.84% per annum.

10. ASSET RETIREMENT OBLIGATIONS

ME has recognized applicable legal obligations for AROs and its associated cost primarily relating to the decommissioning of the TMI-2 nuclear generating facility. ME uses an expected cash flow approach to measure the fair value of its nuclear decommissioning AROs.

ME maintains NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2015 and 2014 was $325 million and $337 million, respectively.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not in the recognition of the liability.

METROPOLITAN EDISON COMPANY
NOTES TO FINANCIAL STATEMENTS (Continued)

The following table summarizes the changes to ME's ARO balances during 2015 and 2014:

ARO Reconciliation	*In millions*	
Balance, January 1, 2014	$	235
Accretion		16
Revisions in estimated cash flows		(64)
Balance, December 31, 2014		187
Accretion		13
Settlements		(1)
Balance, December 31, 2015	$	199

During the fourth quarter of 2014, based on studies completed by a third-party to reassess the estimated costs of decommissioning TMI-2, ME decreased its ARO by $64 million, which offset a regulatory asset. The reduction in the ARO liability of ME was primarily the result of an extension in the number of years in which decommissioning activities are estimated to occur.

11. REGULATORY MATTERS

STATE REGULATION

ME's retail rates, conditions of service, issuance of securities and other matters are subject to regulation in Pennsylvania by the PPUC.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges. A hearing was held on February 25, 2016.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million (ME - $75 million) and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On February 15, 2016, Wellsboro filed a Motion to Withdraw from the proceeding. On February 19, 2016, the remaining parties notified the presiding ALJs that they reached a unanimous settlement in principle which resolves all issues raised in the proceeding, which must be formalized in a Joint Petition for Full Settlement. A telephonic hearing will be held on February 29, 2016 to admit the direct and rebuttal testimony that has been submitted to date and discuss the process for accepting and ruling upon a Joint Petition for Full Settlement. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

FEDERAL REGULATION

With respect to their wholesale services and rates, the Utilities, including ME, are subject to regulation by FERC. Under the FPA, FERC regulates rates for interstate wholesale sales, transmission of electric power, accounting and other matters. FERC regulations require ME to provide open access transmission service at FERC-approved rates, terms and conditions. ME's transmission facilities are subject to functional control by PJM and transmission service using ME's transmission facilities is provided by PJM under the PJM Tariff.

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities, including ME, each have been authorized by FERC to sell wholesale power in interstate commerce and have a market-based rate tariff on file with FERC; although major wholesale purchases remain subject to regulation by the relevant state commissions. As a condition to selling electricity on a wholesale basis at market-based rates, the Utilities, including ME, like other entities granted market-based rate authority, must file electronic quarterly reports with FERC listing their sales transactions for the prior quarter.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on ME. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities, including those of ME, are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on ME's financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on ME cannot be predicted at this time.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of; (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. On February 18, 2016, FERC issued an order authorizing the transaction as requested. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. Final decisions are expected from the NJBPU and PPUC by mid-2016. See Pennsylvania Regulatory above for further discussion of this transaction.

12. COMMITMENTS AND CONTINGENCIES

NUCLEAR INSURANCE

ME maintains property damage insurance provided by NEIL for its interest in the TMI-2 nuclear plant, a permanently shutdown and defueled facility. Under these arrangements, up to $150 million of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. ME pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $0.6 million during a policy year.

ME intends to maintain insurance against nuclear risks as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of ME's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by ME's insurance policies, or to the extent such insurance becomes unavailable in the future, ME would remain at risk for such costs.

The Price-Anderson Act limits public liability relative to a single incident at a nuclear power plant. In connection with TMI-2, ME carries the required ANI third party liability coverage and also has coverage under a Price Anderson indemnity agreement issued by the U.S. NRC. The total available coverage in the event of a nuclear incident is $560 million, which is also the limit of public liability for any nuclear incident involving TMI-2.

ENVIRONMENTAL MATTERS

Prior to November 1999, ME owned and operated electric generation facilities in Pennsylvania. In response to federal and state deregulation initiatives, it separated its electric generation business from its transmission and distribution businesses by transferring all of its generation assets to an affiliate. However, ME retained responsibility for certain liabilities and obligations arising under environmental laws up to the date of transfer. As more fully discussed below, as an historic owner and operator of generation facilities, ME has been subject to claims alleging violations of environmental law and could have exposure for fines and penalties.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, ME must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, ME had approximately $325 million invested in external trusts to be used for the decommissioning and environmental remediation of TMI-2. The values of ME's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, ME's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to ME's normal business operations pending against ME. The loss or range of loss in these matters is not expected to be material to ME. The other potentially material items not otherwise discussed above are described under Note 11, Regulatory Matters of the Notes to Financial Statements.

ME accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where ME determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that ME has legal liability or is otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on ME's financial condition, results of operations and cash flows.

13. TRANSACTIONS WITH AFFILIATED COMPANIES

ME's operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FE's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for ME during the years ended December 31, 2015 and 2014 are as follows:

	2015	2014
	(In millions)	
Revenues	$ 10	$ 10
Expenses:		
Purchased power from affiliates	77	149
Support services	51	47
Interest Expense:		
Interest expense to affiliates	2	2
Interest expense to FE	1	1

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated from FESC, a subsidiary of FE. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

MET-ED EXHIBIT JD-17
ATTACHMENT B

ANNUAL 2015 REPORT

FirstEnergy®

FINANCIAL HIGHLIGHTS

KEY ACCOMPLISHMENTS

- Generated $3.4 billion in cash from operations
- Invested nearly $1 billion to modernize our transmission system as part of our Energizing the Future initiative
- Launched our Cash Flow Improvement Project with the goal of capturing meaningful and sustainable savings across our company
- Secured a 20-year license extension from the Nuclear Regulatory Commission for the Davis-Besse Nuclear Power Station
- Enhanced transmission and distribution system reliability

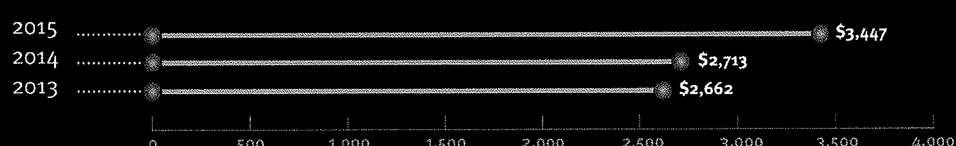
FINANCIALS AT A GLANCE

(dollars in millions, except per share amounts)

	2015	2014	2013
TOTAL REVENUES	$15,026	$15,049	$14,892
NET INCOME	$578	$299	$392
BASIC AND DILUTED EARNINGS per common share	$1.37	$0.71	$0.94
DIVIDENDS PAID per common share	$1.44	$1.44	$2.20
BOOK VALUE per common share	$29.33	$29.49	$30.32

NET CASH FROM OPERATING ACTIVITIES

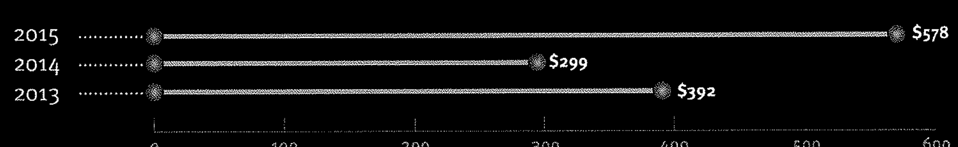
(in millions)



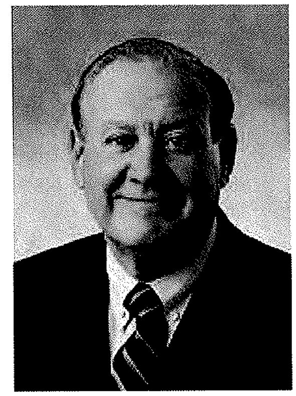
TRANSMISSION AND DISTRIBUTION RELIABILITY INDEX*

NET INCOME

(in millions)



*FirstEnergy's index comprises two indices that are commonly used in the electric utility industry: Transmission Outage Frequency (TOF) and System Average Interruption Duration Index (SAIDI). Our index measures frequency and duration of service interruptions: the better the performance, the higher the score.



Charles E. Jones
President and Chief Executive Officer

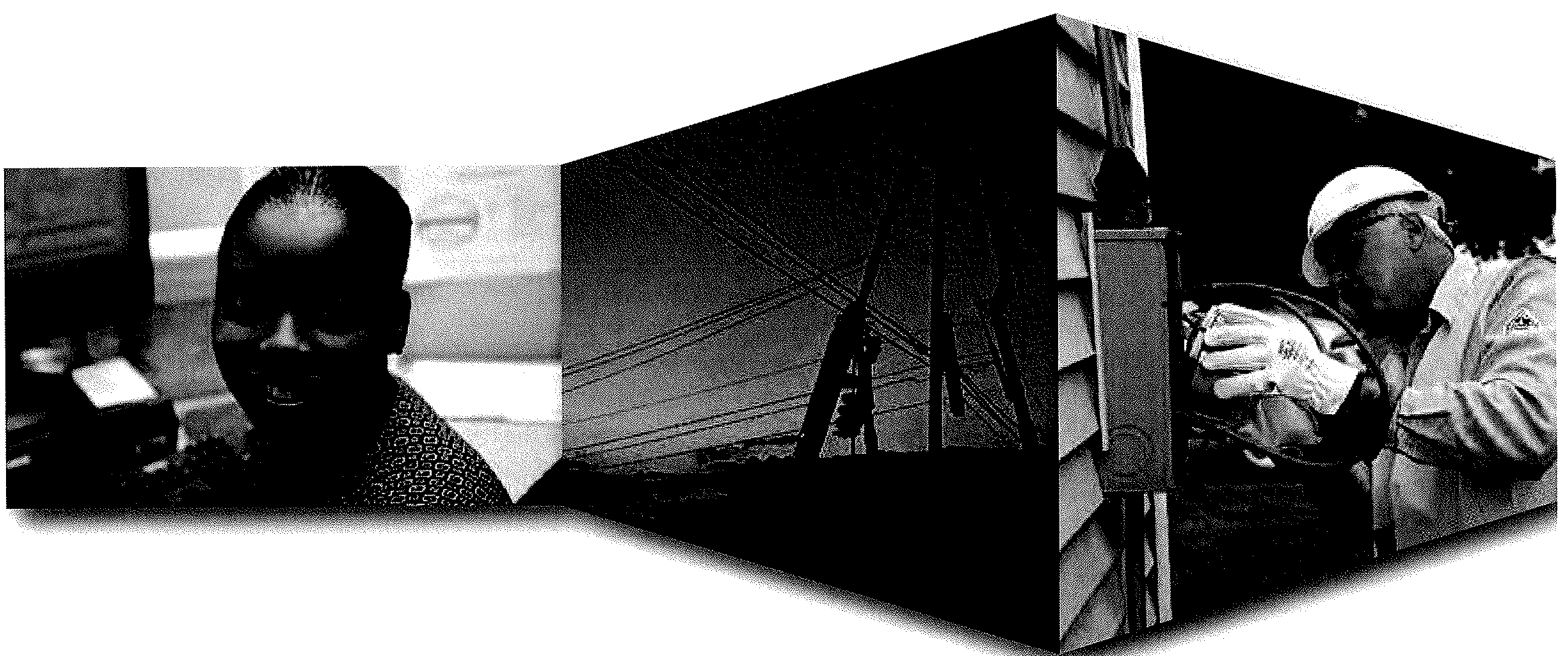
A MESSAGE TO OUR SHAREHOLDERS

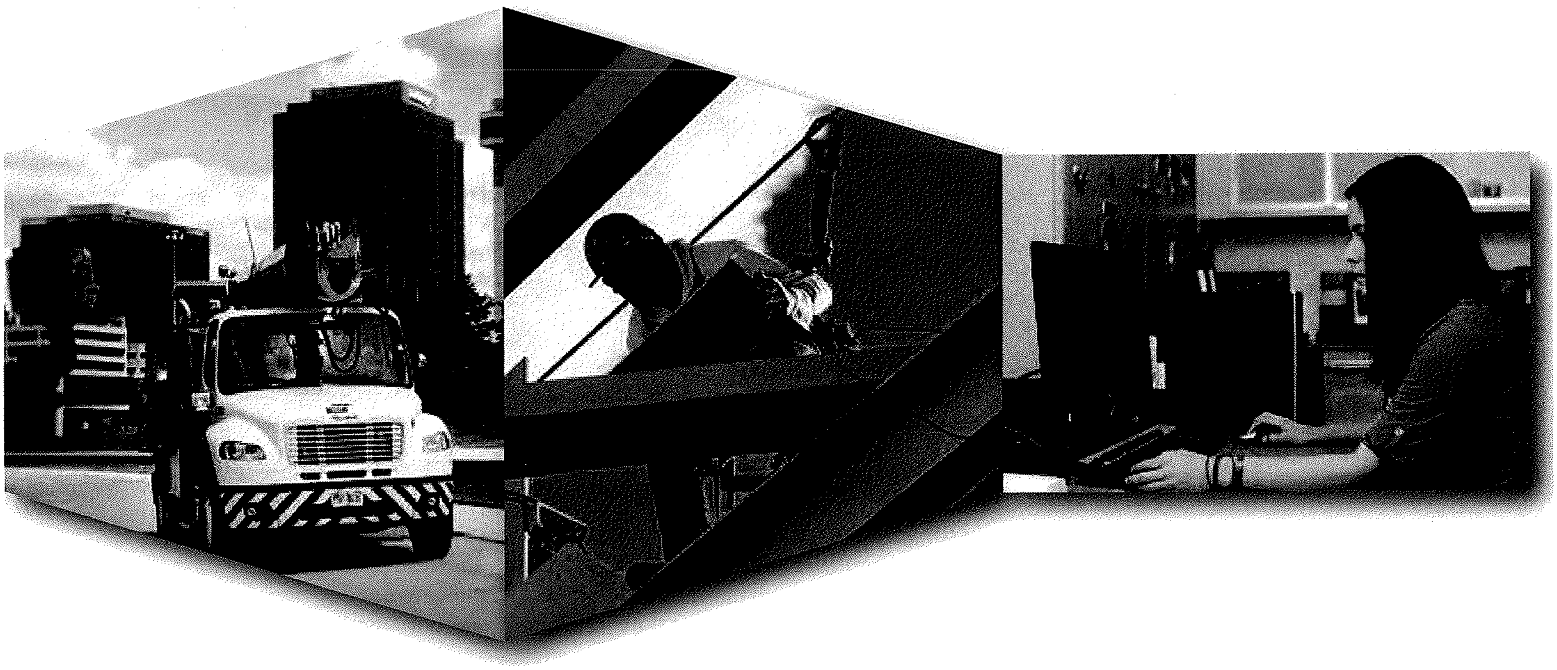
We maintained a strong focus in 2015 on achieving more regulated, customer-focused growth for your company.

Toward that end, we made significant investments to enhance the reliability and efficiency of our electric system. These included $986 million in targeted improvements during the year to our transmission system, and approximately $1.2 billion in capital upgrades that helped our regulated utilities continue to provide reliable service to customers. We also received approval on a forward-looking rate filing for our American Transmission Systems, Inc. (ATSI) transmission company, which will allow more effective and timely recovery of its system investments.

Six of our regulated utilities received approval of settlements in distribution rate cases in 2015, and our rate case in New Jersey also was resolved, resulting in an overall revenue increase of $321 million. In Ohio, the Public Utilities Commission of Ohio (PUCO) is reviewing a settlement agreement with 17 key parties supporting our Electric Security Plan IV (ESP) for The Illuminating Company, Ohio Edison and Toledo Edison. The plan is expected to strengthen your company's financial position in the years ahead and is designed to provide significant benefits to our customers and communities – including more stable rates, a renewed emphasis on energy efficiency and renewable power, and strong support for economic development. The PUCO is expected to rule on the ESP by the end of March.

We also expect to achieve $240 million in annual savings by 2017 through our Cash Flow Improvement Project – a comprehensive effort our employees conducted in 2015, and will closely monitor in the years ahead, to reduce expenses and enhance revenue throughout our operations. In addition, we continue to execute a more conservative strategy for our competitive generation business that minimizes risk while taking advantage of market opportunities.





GROWING OUR
REGULATED OPERATIONS

We're building a stronger energy system through our primary growth platform, Energizing the Future – an initial $4.2 billion investment in the long-term reliability of our transmission system that began in 2014 and runs through 2017. Spanning our entire transmission system, projects funded through the program are designed to meet the future energy needs of customers by adding resiliency to our bulk electric system, enhancing our facilities and equipment, and increasing physical and cyber security.

Initial efforts primarily focused on the ATSI transmission system that encompasses the service areas of Ohio Edison, Toledo Edison, The Illuminating Company and Penn Power, with projects shifting eastward over time to include our other service areas. Work performed to date also has helped us identify $15 billion in additional opportunities across our 24,200-mile transmission system that will benefit customers through further reliability enhancements.

Among other projects, we're reinforcing our system to ensure grid reliability following the retirement of coal-fired power plants in our region. For example, since 2014, we've invested $500 million in transmission projects to support the deactivation of three of our power plants along Lake Erie. As part of this effort, we built a 119-mile transmission line from Beaver County, Pa., to our new Glenwillow substation in suburban Cleveland, as well as five new substations across portions of our Ohio service area.

In addition, we're nearing completion of a transmission reinforcement project in Harrison County, W.Va., that involves the construction of a new substation and a 6-mile transmission line. The project is expected to enhance service reliability for approximately 14,000 customers in the northern portion of West Virginia.

Given that our regulated footprint is aligned with some of the nation's richest shale fields, we're making investments through 2020 to support growth in midstream shale gas operations throughout our service area, including planned expansions that are expected to create 600 megawatts (MW) of new industrial load. For example, we recently completed preliminary site work for a new substation near Smithfield, W.Va., that is expected to support new shale gas operations as well as enhanced service reliability for Mon Power customers. Over the past few years, shale gas development has accounted for approximately 500 MW of new load growth in our region.

We remain committed to providing safe, reliable service to our utility customers. All of our utilities outperformed state requirements for SAIDI – an industry-wide measure of the average outage duration for each customer served.

In the critical area of safety, our companywide OSHA rate reached industry top-quartile performance in 2015. This reflects the great importance we place on safe work practices in every facet of our operations.

A crew member welds a stainless steel roof for one of three, 1 million-gallon water tanks for the dewatering facility under construction at our Bruce Mansfield Plant. The facility is needed to dispose of the plant's coal combustion byproducts following the scheduled closing of the Little Blue Run disposal site at the end of 2016.

CREATING A SMARTER GRID

As part of our Energizing the Future initiative, we began investing in nearly 900 smart grid projects designed to make our transmission system more robust, secure and resistant to extreme weather events as well as cyber and physical attacks.

These smart grid technologies have the potential to significantly improve our response time to outages by enabling more efficient service restoration. In addition, remote monitoring devices can proactively evaluate grid conditions and take corrective actions even before outages occur. We're also upgrading our transmission equipment with advanced technologies designed to enhance the reliability of our system and meet projected load growth in our region.

We continued to move forward with our Pennsylvania smart meter program, installing more than 160,000 smart meters in our Penn Power service area by the end of 2015. Through this state-mandated effort, we plan to deploy more than 2 million smart meters across our Pennsylvania service area by mid-2019.

Although smart grid technologies can be costly, we're receiving full recovery of our investments in Pennsylvania's smart meter program – and we will explore similar programs in other states that allow recovery of these costs. In fact, as part of our proposed ESP, we filed a plan to evaluate smart meter and smart grid technologies across our Ohio service area, subject to PUCO consideration and approval.

NEARLY
40 MILLION
MEGAWATT-HOURS OF CARBON-FREE ELECTRICITY GENERATED BY OUR THREE NUCLEAR POWER STATIONS IN 2015

ENSURING FAIR AND

AFFORDABLE RATES

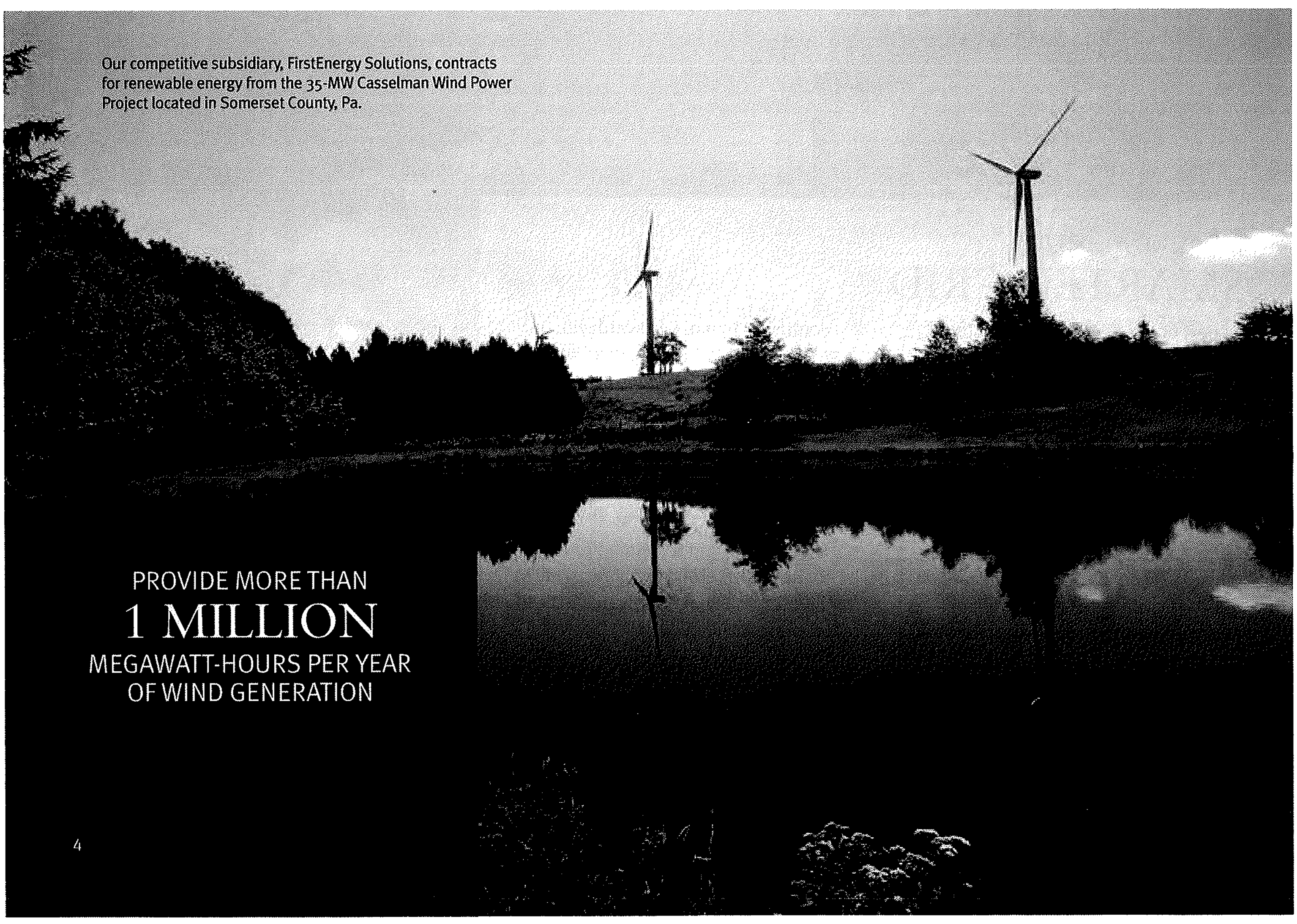
We made significant progress during the year in our efforts to strengthen earnings by ensuring fair, appropriate and timely recovery of our transmission and distribution investments.

In October, the Federal Energy Regulatory Commission (FERC) approved a settlement agreement for a forward-looking rate structure for ATSI, which owns and operates nearly 7,800 miles of transmission lines. This agreement provides more timely recovery of transmission investments that are essential to ensuring the future reliability of our service.

FERC also approved a plan to transfer the transmission assets owned by three of our operating companies – Jersey Central Power & Light (JCP&L), Met-Ed and Penelec – to a new affiliate, Mid-Atlantic Interstate Transmission (MAIT). Similar to our existing ATSI and TrAILCo transmission companies, MAIT will help us more effectively finance and build transmission facilities within our Met-Ed, Penelec and JCP&L service areas while providing stronger support to our Energizing the Future initiative as it expands eastward. Although the New Jersey Board of Public Utilities (BPU) rejected one of the plan's provisions, it continues to review the remainder of the proposal. We also filed a comprehensive settlement agreement with the Pennsylvania Public Utility Commission (PPUC) for approval of MAIT.

Approval of our Ohio ESP by the PUCO would be an important step in our efforts to protect customers from future price volatility. The plan includes a rider that reflects the difference between the cost of an eight-year Purchased Power Agreement (PPA) and our Ohio utilities' associated wholesale market revenues. The PPA supports the continued operation of two of our critical baseload power plants – the Davis-Besse Nuclear Power Station and the W.H. Sammis Plant – which would preserve more than $41 million in annual tax revenues and an estimated 3,000 direct and indirect jobs related to those facilities. Although the PPA has been challenged at FERC, we will continue to advocate for the plan's many benefits in that proceeding.

In February of 2016, the PPUC approved long-term infrastructure improvement plans for our four Pennsylvania utilities, supporting a projected increase in capital investment of nearly $245 million over the next five years to strengthen, upgrade and modernize our distribution systems in the state. The four utilities also filed rate riders that, with PPUC approval, would facilitate recovery of these investments.



Our competitive subsidiary, FirstEnergy Solutions, contracts for renewable energy from the 35-MW Casselman Wind Power Project located in Somerset County, Pa.

LOWERING RISK IN OUR
COMPETITIVE BUSINESS

We continue to execute a conservative sales and generation strategy that offers less risk to the company.

To achieve this goal, our FirstEnergy Solutions subsidiary continued to restructure its sales portfolio to reduce our exposure to weather-sensitive demand and ensure we don't sell more power than we produce. A larger portion of our generation is kept in reserve to minimize our financial risk when energy prices increase and ensure power is available to sell when market conditions are favorable.

We're maintaining our support of governmental aggregation and other higher-margin sales while pursuing wholesale opportunities that align with our generation portfolio. We also remain committed to economically dispatching our fleet and operating our units with greater flexibility.

FirstEnergy Nuclear Operating Company (FENOC) reached a significant milestone in 2015 when the Nuclear Regulatory Commission approved a 20-year license extension for the Davis-Besse Nuclear Power Station, allowing the unit to operate until 2037. In addition, improved reliability and outage execution enabled FENOC to produce approximately 1 million megawatt-hours over its original plan for the year, further improving commodity margin.

PJM Interconnection's new Capacity Performance product had a positive impact in more properly valuing essential and highly reliable baseload generating resources. Capacity auctions held in August and September of 2015 are expected to improve revenues by $1.1 billion from June 2016 through May 2019. However, markets continue to fall short of reflecting the true cost of operating our baseload power plants.

MEETING OUR ENVIRONMENTAL
COMMITMENTS

In 2015, we continued to make progress to improve the environmental performance of our operations.

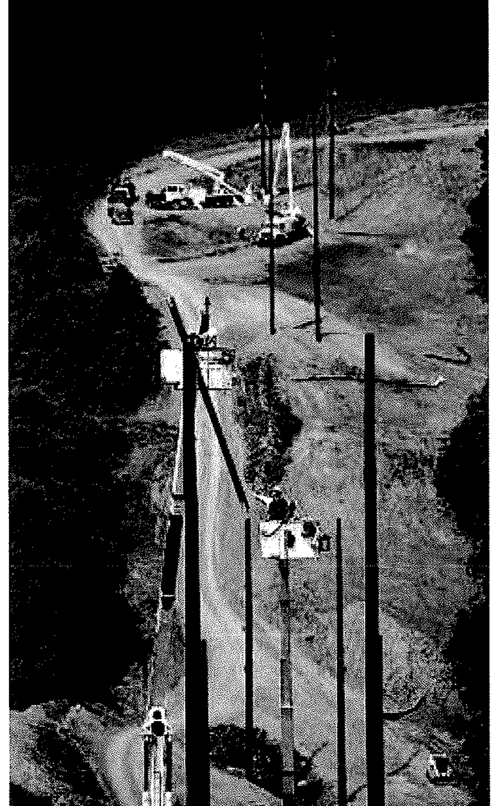
Our proposed Ohio ESP includes a goal to reduce carbon dioxide emissions by at least 90 percent below 2005 levels by 2045 – exceeding President Obama's goal of achieving economywide reductions of 80 percent or more by 2050.

The Clean Power Plan called for individual states to develop plans for meeting the U.S. Environmental Protection Agency's state-specific emission reduction goals. However, on Feb. 9, 2016, the U.S. Supreme Court granted a petition from 27 states and other stakeholders to halt enforcement of the Clean Power Plan's final rule until after all legal challenges are resolved.

FirstEnergy submitted extensive comments before the rule was finalized, and we're continuing to engage federal and state policymakers on issues related to our ongoing efforts to ensure the availability of clean, reliable and affordable energy resources for customers.

We've also made the significant investments needed to comply with the EPA's Mercury and Air Toxics Standards and other requirements, and we will continue to invest in our fossil fleet to help maintain reliable and affordable supplies of power for customers as we make the transition to a cleaner energy future.

\$4.2 BILLION
IN PLANNED TRANSMISSION INVESTMENTS FROM 2014 THROUGH 2017



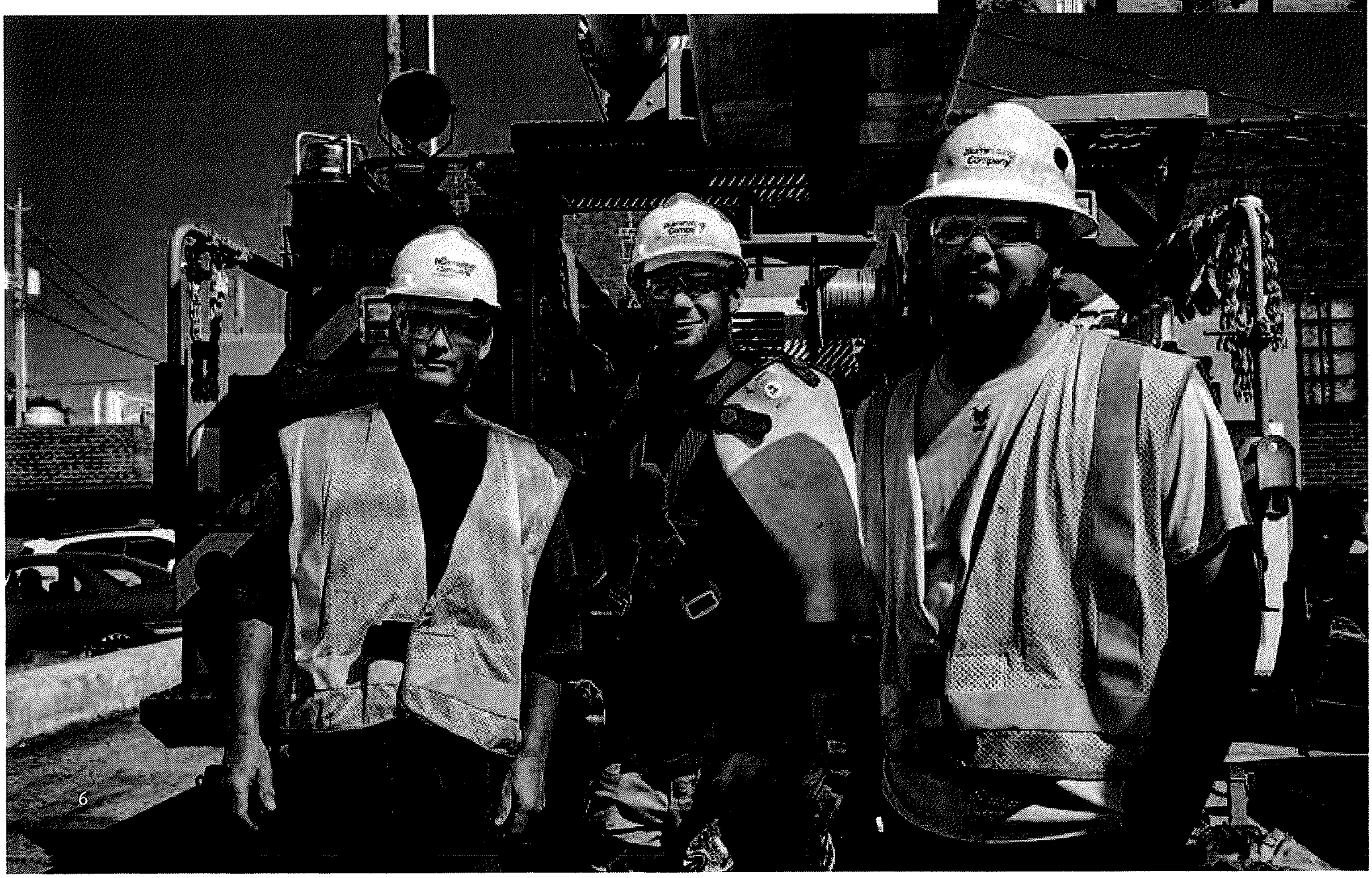
SETTING A COURSE FOR THE FUTURE

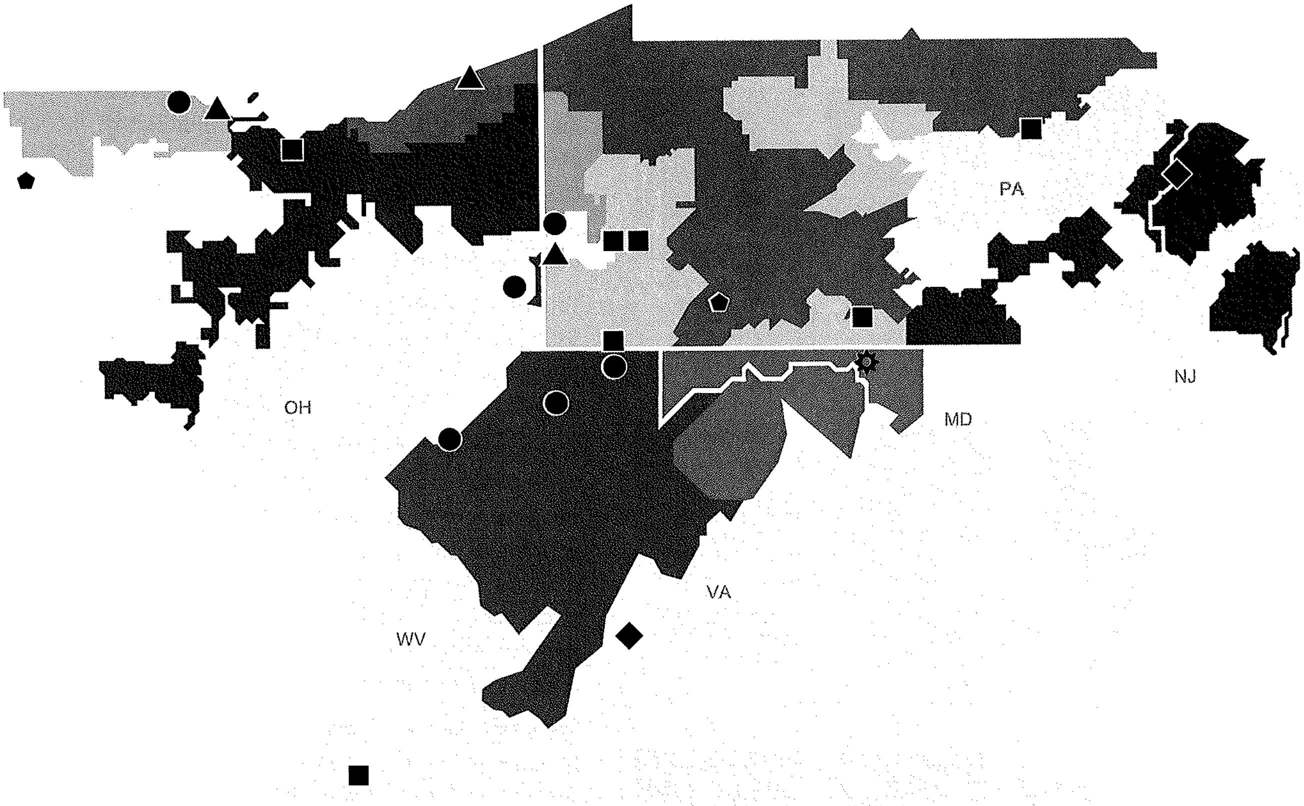
I'm proud of what our employees have accomplished, and I'm confident they will help us succeed in the future by continuing to provide customers with the level of service they expect and deserve.

We're pursuing the right strategy for your company. By achieving solid performance across our three business sectors – distribution, transmission and generation – and remaining focused on meeting our customers' immediate and long-term energy needs, we can deliver more sustainable growth and greater financial stability for FirstEnergy in the years ahead.

Thank you for your support as we work to achieve continued success for your company.

Charles E. Jones
President and Chief Executive Officer
March 16, 2016





CORPORATE PROFILE

Headquartered in Akron, Ohio, FirstEnergy is a leading regional energy provider dedicated to safety, operational excellence and responsive customer service. Our subsidiaries are involved in the generation, transmission and distribution of electricity.

Our 10 utility operating companies form one of the nation's largest investor-owned electric systems based on 6 million customers served within a nearly 65,000-square-mile area of Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York.

Our generation subsidiaries control nearly 17,000 megawatts (MW) of capacity from a diversified mix of scrubbed coal, nuclear, natural gas, oil, hydroelectric pumped-storage and contracted wind and solar resources – including 1,900 MW of renewable energy. The company's transmission subsidiaries operate approximately 24,200 miles of transmission lines connecting the Midwest and Mid-Atlantic regions.

FirstEnergy Solutions, our competitive subsidiary, is a retail energy supplier serving approximately 1.6 million residential, commercial and industrial customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan and Illinois.

Ohio
- Ohio Edison
- The Illuminating Company
- Toledo Edison

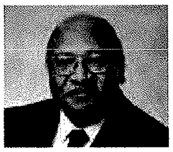
Pennsylvania
- Met-Ed
- Penelec
- Penn Power
- West Penn Power

West Virginia/Maryland
- Mon Power
- Potomac Edison

New Jersey
- Jersey Central Power & Light

Generating Stations
- ● Coal
- ■ Gas/Oil
- ◆ Hydro
- ▲ Nuclear
- ⬟ Wind
- ✿ Solar

FIRSTENERGY BOARD OF DIRECTORS

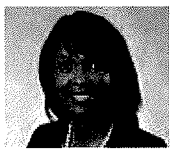


Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (CitiGroup).

Michael J. Anderson
Chairman of the Board of The Andersons, Inc. (diversified agribusiness).

William T. Cottle
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company.

Robert B. Heisler, Jr.
Retired, formerly Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.



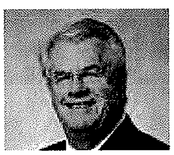
Julia L. Johnson
President of NetCommunications, LLC (regulatory and public affairs firm).

Charles E. Jones
President and Chief Executive Officer of FirstEnergy Corp.

Ted J. Kleisner
Retired, formerly Chairman of the Board and Chief Executive Officer of Hershey Entertainment & Resorts Company.

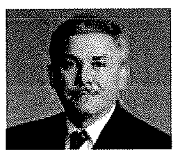
Donald T. Misheff
Retired, formerly Managing Partner of the Northeast Ohio offices of Ernst & Young LLP.

Thomas N. Mitchell
Retired, formerly President, CEO and Director of Ontario Power Generation Inc.



Ernest J. Novak, Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.

Christopher D. Pappas
President and Chief Executive Officer of Trinseo S.A., formerly Styron LLC (plastics, latex and rubber producer).



Luis A. Reyes
Retired, formerly Regional Administrator of the U.S. Nuclear Regulatory Commission.

George M. Smart
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc.

Dr. Jerry Sue Thornton
CEO of Dream Catcher Educational Consulting (higher education coaching and professional development). Retired President of Cuyahoga Community College.

FIRSTENERGY CORP. EXECUTIVE OFFICERS*

Charles E. Jones
President and Chief Executive Officer

Leila L. Vespoli
Executive Vice President, Markets and Chief Legal Officer

James H. Lash
Executive Vice President and President, FE Generation

James F. Pearson
Executive Vice President and Chief Financial Officer

Gary D. Benz
Senior Vice President, Strategy

Lynn M. Cavalier
Chief Human Resource Officer

Dennis M. Chack
Senior Vice President, Marketing and Branding

Michael J. Dowling
Senior Vice President, External Affairs

Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer

Charles D. Lasky
Senior Vice President, Human Resources

Donald R. Schneider
President, FirstEnergy Solutions

Steven E. Strah
Senior Vice President and President, FirstEnergy Utilities

K. Jon Taylor
Vice President, Controller and Chief Accounting Officer

*More detailed information on the principal occupation or employment of each of our executive officers and the principal business of any organization by which FirstEnergy Executive Officers are employed may be found on page 145 of this report.

DEAR SHAREHOLDERS:

FirstEnergy's management team and employees made significant progress in 2015. Your Board of Directors commends their efforts to achieve customer-focused growth in the company's regulated utility operations, manage risk in its competitive business, and reduce expenses.

Your Board provided an annual dividend rate of $1.44 per share in 2015. As FirstEnergy addresses future opportunities and challenges, we will continue to review the dividend on a quarterly basis.

Your Board is committed to maintaining the appropriate practices and policies that help ensure good corporate governance. We also support your management team as it focuses on ensuring employee safety, providing outstanding service to customers, enhancing the company's environmental performance, and delivering consistent and predictable financial results.

I welcome Thomas N. Mitchell, who was elected to serve on the company's Board in January 2016. Tom is a well-respected nuclear industry veteran with 38 years of experience in the field, including leadership positions at the World Association of Nuclear Operators, the Institute of Nuclear Power Operations, the Nuclear Energy Institute and the Electric Power Research Institute.

Your Board remains dedicated to representing your interests and enhancing the value of your investment in FirstEnergy. Thank you for your ongoing support.

Sincerely,

George M Smart

George M. Smart,
Chairman of the Board

2015
ANNUAL REPORT

CONTENTS

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, which provided legal, financial and other corporate support services to the former AE subsidiaries
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and equity method investee of MP
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities
Buchanan Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply
Buchanan Generation	Buchanan Generation, LLC, a joint venture between AE Supply and CNX Gas Corporation
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FELHC, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, which is the parent of ATSI and TrAIL and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly-owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly-owned subsidiary of FG, which owns various leasehold interests in Bruce Mansfield Unit 1
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	Global Rail Group, LLC, a subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FE on November 7, 2001
Green Valley	Green Valley Hydro, LLC, which owned hydro generating stations
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland and West Virginia electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	Signal Peak Energy, LLC, an indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

The following abbreviations and acronyms are used to identify frequently used terms in this report:

AAA	American Arbitration Association
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMT	Alternative Minimum Tax
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
ASU	Accounting Standards Update
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CBA	Collective Bargaining Agreement
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CONE	Cost-of-New-Entry
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EMAAC	Eastern Mid-Atlantic Area Council of PJM
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
ESTIP	Executive Short-Term Incentive Program
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board

FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCl	HydroChloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICP 2007	FirstEnergy Corp. 2007 Incentive Plan
ICP 2015	FirstEnergy Corp. 2015 Incentive Compensation Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
KPI	Key Performance Indicator
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LED	Light Emitting Diode
LMP	Locational Marginal Price
LOC	Letter of Credit
LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MAAC	Mid-Atlantic Area Council of PJM
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator

NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
OTC	Over The Counter
OTTI	Other-Than-Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Purchase Power Agreement
PPB	Parts per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PTC	Price-to-Compare
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROE	Return on Equity
RPM	Reliability Pricing Model
RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB221	Amended Substitute Senate Bill No. 221
SB310	Substitute Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service

SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
TTS	Temporary Transaction Surcharge
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VRR	Variable Resource Requirement
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2015	2014	2013	2012	2011
	(In millions, except per share amounts)				
Revenues	$ 15,026	$ 15,049	$ 14,892	$ 15,255	$ 16,087
Income From Continuing Operations	$ 578	$ 213	$ 375	$ 755	$ 856
Earnings Available to FirstEnergy Corp.	$ 578	$ 299	$ 392	$ 770	$ 885
Earnings per Share of Common Stock:					
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.81	$ 2.19
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Basic - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.85	$ 2.22
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 1.80	$ 2.18
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	0.04	0.03
Diluted - Earnings Available to FirstEnergy Corp.	$ 1.37	$ 0.71	$ 0.94	$ 1.84	$ 2.21
Weighted Average Shares Outstanding:					
Basic	422	420	418	418	399
Diluted	424	421	419	419	401
Dividends Declared per Share of Common Stock	$ 1.44	$ 1.44	$ 1.65	$ 2.20	$ 2.20
Total Assets[(1)]	$ 52,187	$ 51,648	$ 50,058	$ 50,175	$ 47,410
Capitalization as of December 31:					
Total Equity	$ 12,422	$ 12,422	$ 12,695	$ 13,093	$ 13,299
Long-Term Debt and Other Long-Term Obligations	19,192	19,176	15,831	15,179	15,716
Total Capitalization	$ 31,614	$ 31,598	$ 28,526	$ 28,272	$ 29,015

[(1)]Reflects the application of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires all accumulated deferred income taxes to be classified as non-current. The retrospective change decreased Total Assets as of December 31 as follows: 2014 - $518 million, 2013 -$366 million, 2012 - $319 million as these amounts were reclassified from current assets to non-current liabilities.

PRICE RANGE OF COMMON STOCK

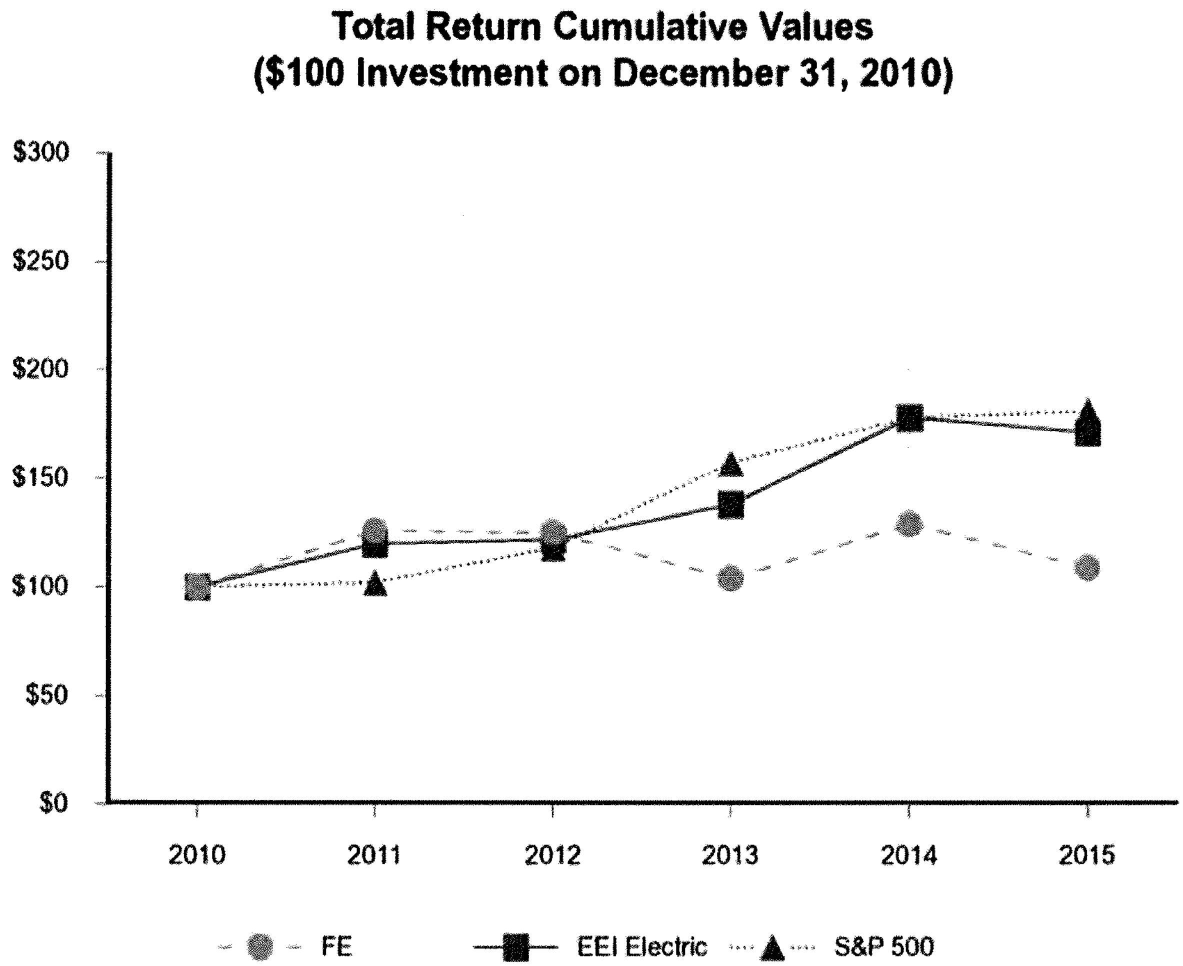
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2015		2014	
	High	Low	High	Low
First Quarter	$ 41.68	$ 33.82	$ 34.28	$ 30.10
Second Quarter	$ 37.05	$ 32.46	$ 35.59	$ 31.17
Third Quarter	$ 35.09	$ 30.31	$ 34.95	$ 29.98
Fourth Quarter	$ 33.00	$ 28.89	$ 40.84	$ 33.04
Yearly	$ 41.68	$ 28.89	$ 40.84	$ 29.98

Closing prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2010 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 90,633 and 90,346 holders of 423,560,397 and 423,650,645 shares of FirstEnergy's common stock as of December 31, 2015 and January 31, 2016, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11, Capitalization of the Combined Notes to Consolidated Financial Statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

Forward-Looking Statements: This report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "forecast," "target," "will," "intend," "believe," "project," "estimate," "plan" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including but not limited to, the proposed transmission asset transfer to MAIT, and the effectiveness of our strategy to reflect a more regulated business profile.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and the ESP IV in Ohio.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; and FERC's compliance and enforcement activity, including compliance and enforcement activity related to NERC's mandatory reliability standards.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil prices, and their availability and impact on margins and asset valuations.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, the effects of the EPA's CPP, CCR, CSAPR and MATS programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation, or potential regulatory initiatives or rulemakings (including that such initiatives or rulemakings could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments and as it relates to the reliability of the transmission grid, the timing thereof.
- The impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building at Davis-Besse.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our cash flow improvement plan and other proposed capital raising initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.

- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

These forward looking statements are also qualified by, and should be read together with, the risk factors included in (a) Item 1A. Risk Factors of our Annual Report on Form 10-K filed with the SEC on February 16, 2016, (b) this Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) other factors discussed herein and in other filings with the SEC by FE. The foregoing review of factors also should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRSTENERGY'S BUSINESS

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission, and CES.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

The service areas of, and customers served by, FirstEnergy's regulated distribution utilities are summarized below (in thousands):

Company	Area Served	Customers Served [1]
OE	Central and Northeastern Ohio	1,038
Penn	Western Pennsylvania	164
CEI	Northeastern Ohio	746
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,109
ME	Eastern Pennsylvania	561
PN	Western Pennsylvania	588
WP	Southwest, South Central and Northern Pennsylvania	723
MP	Northern, Central and Southeastern West Virginia	390
PE	Western Maryland and Eastern West Virginia	401
		6,028

[1] As of December 31, 2015

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity. The CES segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment's customers.

The CES segment expects to sell its annual generation output of approximately 75 to 80 million MWHs, with up to an additional 5 million MWHs available from PPAs for wind, solar and its entitlement from OVEC, through a target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct), 10 to 20 million MWHs in block wholesale sales, including Structured Sales, and 10 to 20 million MWHs of spot wholesale sales.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy continues to capitalize on investment opportunities available in its Regulated Transmission and Regulated Distribution businesses while implementing a conservative hedging strategy at its Competitive business. FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy over time.

FirstEnergy's regulated investment strategy focuses on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years.

Regulated Transmission

The centerpiece of FirstEnergy's regulated investment strategy is the *Energizing the Future* transmission expansion plan. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize FirstEnergy's transmission system.

In conjunction with its transmission expansion plan, in 2015 ATSI received FERC-approval of its "forward looking" rate, implemented on January 1, 2015, where transmission rates are based on estimated costs for the current year with an annual true up, and an ROE of: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and 10.38% effective January 1, 2016, unless changed pursuant to Section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Additionally, in June 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. If approved, MAIT will operate similar to FET's two existing stand-alone transmission subsidiaries ATSI and TrAIL. FERC approval is expected in March 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

Regulated Distribution

During 2015, FirstEnergy continued to pursue key regulatory initiatives across its utility footprint, focusing on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives included:

- The Ohio Companies' ESP IV, *Powering Ohio's Progress:* The ESP IV, including the impact of filed stipulations in the case, contemplates continuing a distribution rate freeze through May 2024 while helping ensure continued availability of more than 3,200 MWs of FirstEnergy's critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers. Evidentiary hearings commenced in August 2015. On December 1, 2015, FirstEnergy's Ohio Companies filed an additional settlement at the PUCO, which included the PUCO Staff as a signatory party, that sets forth ambitious steps to help safeguard customers against retail generation price increases in future years, deploy new energy efficiency programs, and provide a clear path to a cleaner energy future by establishing a goal to substantially reduce carbon emissions. The settlement includes an eight-year rate provision (Rider RRS) designed to help protect customers against rising retail price increases and market volatility, while helping preserve vital baseload power plants that serve Ohio customers and provide thousands of family-sustaining jobs in the state. The plants involved include the Davis-Besse Nuclear Power Station, the W.H. Sammis Plant, and a portion of the output of OVEC units in Gallipolis, Ohio, and Madison, Indiana. A decision is anticipated in March 2016. On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge, in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

- Implementation of New Rates in Pennsylvania for ME, PN, Penn and WP: The new rates were approved in April 2015 and went into effect in May 2015, providing for an increase in annual revenues of approximately $293 million and approximately $88 million of additional annual operating expenses. Furthermore, in October 2015, the Pennsylvania companies filed LTIIPs with the PPUC for infrastructure improvements over the 2016 to 2020 period totaling nearly $245 million, which were approved on February 11, 2016. The Pennsylvania Companies filed DSIC riders on February 16, 2016, for quarterly cost recovery associated with the projects approved in the LTIIPs.

- Implementation of New Rates in West Virginia for MP and PE: The new rates were approved and went into effect in February 2015, resulting in recovery of $63 million annually for reliability investments and expenses, storm damage expenses, and investments in operating improvements and environmental compliance at MP's and PE's regulated coal-fired power plants in West Virginia. MP and PE also received orders in December 2015 in their ENEC case and their biennial vegetation management program surcharge reconciliation, resulting in revenue increases, effective January 1, 2016, totaling $96.9 million and $36.7 million, respectively, to recover deferred costs.

Additionally, during 2015, the NJBPU issued orders on JCP&L's base rate proceedings and its generic storm proceedings resulting in a reduction of approximately $34 million in annual revenues, inclusive of recovery of 2011 and 2012 storm costs, as well as the NJBPU's recently modified CTA policy. As part of the base rate order, JCP&L is required to file another base rate case no later than April 1, 2017.

Competitive Energy Services

FirstEnergy continues its strategy for its competitive business to more effectively hedge its generation by reducing exposure to weather-sensitive load in certain sales channels and pursuing high-margin sales, while leaving a portion of its generation available to capture future market opportunities or to mitigate risk. This strategy is designed to position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. On average, the CES segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs available from purchased power agreements for wind, solar and its entitlement from OVEC. In 2015, CES sold approximately 75 million MWHs of which 68 million MWHs were through contract sales with another 7 million MWHs of wholesale sales. As of December 31, 2015, committed sales for 2016 and 2017 were approximately 61 million MWHs and 38 million MWHs, respectively.

From a generation perspective, FirstEnergy continues to focus on ensuring its competitive fleet is cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. FirstEnergy's total cost for MATS compliance is expected to be approximately $345 million ($168 million at CES and $177 million at Regulated Distribution), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

During 2015, FirstEnergy completed scheduled shutdowns for three of its nuclear units - Beaver Valley Unit 1 and Unit 2 and the Perry Nuclear Power plant - for refueling and maintenance. During the outages, fuel assemblies were exchanged and numerous inspections and preventative maintenance and improvement projects were completed to ensure continued safe and reliable operations. Additionally, in December 2015, the NRC approved a 20-year license extension for the Davis-Besse Nuclear Power Station allowing the unit to operate until 2037.

Also, in 2015, PJM conducted the 2015 BRA for the 2018/2019 delivery year and Capacity Performance transition auctions for the 2016/2017 and 2017/2018 delivery years. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				**2017 - 2018**				**2018 - 2019***			
	Legacy Obligation		**Capacity Performance**		**Legacy Obligation**		**Capacity Performance**		**Base Generation**		**Capacity Performance**	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

Projected CES Capacity Revenue* ($ Millions)

	2016	**2017**	**2018**	**2019 (through 5/31)**
Capacity Revenue	$815	$590	$620	$260

*Includes revenues from the results of incremental/transitional capacity auctions, bilateral transactions and capacity transfer rights.

STRATEGY AND OUTLOOK

FirstEnergy owns a large and diverse mix of assets managed in an integrated model, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a competitive operations segment that owns or controls over 13,000 MWs of generation with a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy continues to focus on developing its transmission business, strengthening its regulated utilities, and managing overall risk and conservatively operating its competitive business.

FirstEnergy continues to focus on investment opportunities in its Regulated Transmission and Regulated Distribution segments. This investment strategy is focused on delivering enhanced customer service and reliability, strengthening grid and cyber-security, and adding resiliency and operating flexibility to its transmission and distribution infrastructure. FirstEnergy expects to fund these investments through a combination of cash from operations, debt, and, depending on the regulated operating company, capital contributions from its parent. In the future, FirstEnergy may consider additional equity to fund capital requirements in its regulated operations.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses.

FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at each business unit, while improving metrics at FirstEnergy Corp. over time. As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Regulated Transmission

As noted above, the centerpiece of FirstEnergy's growth strategy is a $4.2 billion investment in the *Energizing the Future* program from 2014 through 2017. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. This program is focused on a large number of small projects within the company's 24,000 mile service territory that improve service to customers. The projects within the program are either regulatory required or support reliability enhancement. Regulatory required projects include those requested by PJM to support grid reliability, generator deactivations, or shale gas expansion activities. The second category of projects, those that support reliability enhancement, focus on replacing aging equipment; increasing automation, communication, and security within the system; and increasing load serving capability. In the initial years of the program, the majority of the projects are located within the ATSI system, with expectations to move east across FirstEnergy's service territory over time. An additional $15 billion in transmission investment opportunities have been identified across the system beyond the 2014-2017 period, making this a continuing and sustainable platform for investment.

In 2016, FirstEnergy expects to receive approval to transfer transmission assets of JCP&L, Met-Ed and Penelec to MAIT, a new stand-alone transmission subsidiary.

Regulated Distribution

The five-state service territory served by FirstEnergy's Regulated Distribution segment also offers substantial opportunities for future investments to improve service to more than 6 million customers. In 2015, FirstEnergy completed major rate cases in West Virginia, Pennsylvania and New Jersey. In Pennsylvania, a filing for an infrastructure improvement plan that includes an investment of $245 million through 2020 was approved by the PPUC on February 11, 2016, and in Ohio, a comprehensive settlement in the ESP IV is pending PUCO approval. The ESP IV settlement contains additional opportunities for investment in the Ohio Companies, including grid modernization and energy efficiency as well as continuation of Rider DCR with revenue caps increasing $180 million over the term of the ESP IV. The settlement also includes a FERC-jurisdictional PPA where the Ohio Companies would purchase the output from FES' Davis-Besse nuclear plant, Sammis coal plant and entitlement to OVEC generation output, a total of 3,244 MW, for an eight-year term beginning June 1, 2016.

FirstEnergy also continues to closely monitor sales trends across its utility footprint. Within its Regulated Distribution segment, FirstEnergy continues to be impacted by lower customer usage as a result of energy efficiency mandates and products. During 2015, electric distribution deliveries on a weather-adjusted basis declined 1.6% in the residential customer class and 0.6% in the commercial customer class as compared to 2014. Furthermore, in the industrial sector, increases in the shale gas sector were more than offset with lower usage in the steel and mining sectors, resulting in an overall decrease in the industrial sector of 2.0%.

CES

FirstEnergy continues to focus on maintaining the value of its competitive business and continues to advocate for reforms that ensure the competitive wholesale markets adequately value baseload generation, which is essential for maintaining grid reliability. While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last several years to reposition this business for such a recovery. CES uses a conservative hedging strategy, and expects to sell its annual generation resources of approximately 75-80 million MWHs through a combination of retail and wholesale sales, maintaining 10-20 million MWHs to mitigate risk in the event of unplanned outages or extreme weather or to take advantage of market upside opportunities through the wholesale spot market.

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Years Ended December 31, 2015	2014	2013	Increase (Decrease) 2015 vs 2014		2014 vs 2013	
REVENUES:	$ 15,026	$ 15,049	$ 14,892	$ (23)	— %	$ 157	1 %
OPERATING EXPENSES:							
Fuel	1,855	2,280	2,496	(425)	(19)%	(216)	(9)%
Purchased power	4,318	4,716	3,963	(398)	(8)%	753	19 %
Other operating expenses	3,749	3,962	3,593	(213)	(5)%	369	10 %
Pension and OPEB mark-to-market adjustment	242	835	(256)	(593)	(71)%	1,091	(426)%
Provision for depreciation	1,282	1,220	1,202	62	5 %	18	1 %
Amortization of regulatory assets, net	268	12	539	256	2,133 %	(527)	(98)%
General taxes	978	962	978	16	2 %	(16)	(2)%
Impairment of long-lived assets	42	—	795	42	— %	(795)	(100)%
Total operating expenses	12,734	13,987	13,310	(1,253)	(9)%	677	5 %
OPERATING INCOME	2,292	1,062	1,582	1,230	116 %	(520)	(33)%
OTHER INCOME (EXPENSE):							
Loss on debt redemptions	—	(8)	(132)	8	(100)%	124	(94)%
Investment income (loss)	(22)	72	33	(94)	(131)%	39	118 %
Impairment of equity method investment	(362)	—	—	(362)	— %	—	— %
Interest expense	(1,132)	(1,073)	(1,016)	(59)	5 %	(57)	6 %
Capitalized financing costs	117	118	103	(1)	(1)%	15	15 %
Total other expense	(1,399)	(891)	(1,012)	(508)	57 %	121	(12)%
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570	722	422 %	(399)	(70)%
INCOME TAXES (BENEFITS)	315	(42)	195	357	(850)%	(237)	(122)%
INCOME FROM CONTINUING OPERATIONS	578	213	375	365	171 %	(162)	(43)%
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17	(86)	(100)%	69	406 %
NET INCOME	$ 578	$ 299	$ 392	$ 279	93 %	$ (93)	(24)%
EARNINGS PER SHARE OF COMMON STOCK:							
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Basic - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	169 %	$ (0.39)	(43)%
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04	(0.20)	(100)%	0.16	400 %
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94	$ 0.66	93 %	$ (0.23)	(24)%

FirstEnergy's net income in 2015 was $578 million, or basic and diluted earnings of $1.37 per share of common stock, compared with $299 million, or basic and diluted earnings of $0.71 per share of common stock in 2014, and $392 million, or basic and diluted earnings of $0.94 per share of common stock in 2013. Highlights of the key changes in year-over-year financial results are included below:

2015 compared with 2014

As further discussed below, FirstEnergy's 2015 income from continuing operations increased $365 million as compared to 2014, resulting from a year-over-year improvement of $506 million at CES, $153 million at Regulated Distribution and $75 million at Regulated Transmission, partially offset by a $369 million decrease at Corporate/Other.

In 2015, FirstEnergy's revenues decreased $23 million as compared to 2014, primarily resulting from a $905 million decrease at CES partially offset by a $523 million increase at Regulated Distribution and a $242 million increase at Regulated Transmission.

- The decrease in revenue at CES resulted from a 31 million MWHs decline in contract sales, in line with CES' strategy discussed above, partially offset by higher wholesale sales, including increased capacity revenue associated with higher capacity auction prices.
- The increase in revenue at Regulated Distribution resulted from the implementation of new rates at certain operating companies as well as a year-over-year increase in retail generation revenue, resulting from a lower number of customers shopping with an alternative generation supplier and higher retail transmission revenue, which is recovering higher transmission related expenses. Distribution deliveries decreased 0.8%, or 1.1 million MWHs, as weather adjusted sales declined as a result of energy efficiency mandates and products and decreases in certain industrial sectors, partially offset by an increase in weather-related sales.

- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses as well as ATSI's transition to a forward-looking rate, effective January 1, 2015. These increases were partially offset by a lower ROE at ATSI in the last six months of 2015 as part of the FERC-approved settlement discussed above.

Operating expenses decreased $1,253 million in 2015 as compared to 2014, including a $593 million decrease in the Company's pension and OPEB mark-to-market adjustment, reflecting a decrease at CES of $1,747 million, partially offset by increases at Regulated Distribution and Regulated Transmission of $255 million and $73 million, respectively.

Changes in certain operating expenses include the following:

- Fuel expense declined $425 million, primarily at CES, resulting from lower fossil generation associated with low energy prices, lower unit costs, and lower settlement and termination charges on fuel and transportation contracts.
- Purchased power decreased $398 million, primarily reflecting lower volumes at CES, resulting from lower contract sales, partially offset by higher volumes at Regulated Distribution due to lower customer shopping as discussed above, and higher capacity expense associated with higher capacity rates.
- Other operating expenses decreased $213 million, primarily reflecting a decrease at CES associated with lower PJM transmission, mark-to-market and retail-related costs partially offset by higher nuclear planned outage costs, partially offset by an increase at Regulated Distribution, resulting from higher network transmission expenses, which are recovered through transmission rates as discussed above, and higher operating and maintenance expenses associated with reliability improvements.
- Amortization of regulatory assets, net increased $256 million primarily reflecting the recovery of deferred costs, including storm costs, associated with the implementation of new rates discussed above.

FirstEnergy's other expenses increased $508 million, or 57%, year-over-year, primarily resulting from a $362 million pre-tax, non-cash impairment charge associated with FEV's investment in Global Holding, lower investment income, including a $65 million increase in OTTI, and higher interest expense associated with higher average debt levels.

FirstEnergy's effective tax rate on income from continuing operations was 35.3% in 2015 compared to (24.6)% in 2014. The increase in the effective tax rate was attributable to tax planning initiatives executed during 2014, including tax benefits associated with a change in accounting method with the IRS for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain state tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

2014 compared with 2013

FirstEnergy's 2014 income from continuing operations decreased $162 million as compared to 2013 resulting from a year-over-year decline of $182 million at CES and $36 million at Regulated Distribution, partially offset by a year-over-year improvement at Regulated Transmission of $9 million and $47 million at Corporate/Other.

In 2014, FirstEnergy's revenue increased $157 million compared to 2013. The increase resulted from a $382 million increase at Regulated Distribution and a $38 million increase at Regulated Transmission, partially offset by a decrease in CES revenues of $209 million.

- The increase in revenue at Regulated Distribution resulted from higher wholesale generation sales associated with the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of generation from AE Supply.
- The increase at Regulated Transmission primarily reflected a higher rate base and recovery of incremental operating expenses.
- The decrease at CES resulted from lower contract sales as in 2014, CES began to reduce its exposure to weather sensitive load to more effectively hedge its generation, targeting annual contract sales of 65 to 75 million MWHs as compared to the 109 million MWHs sold in 2013. This change in strategy resulted in a 9% decrease in MWH sales in 2014 as compared to 2013.

Operating expenses increased $677 million in 2014 compared to 2013, including a $1,091 million increase in FirstEnergy's Pension and OPEB mark-to-market adjustment, primarily reflecting an increase at Regulated Distribution of $428 million, CES of $265 million and Regulated Transmission of $40 million.

Changes in certain operating expenses include the following:

- Lower fuel expense of $216 million, primarily reflected the deactivation of power plants in 2013 and increased outages. Fuel expense at CES and Regulated Distribution was further impacted by the October 2013 Harrison/Pleasants asset transfer.
- Purchased power increased $753 million, primarily reflecting higher CES purchases resulting from plant deactivations, increased outages and the asset transfer discussed above as well as higher unit pricing and capacity expense. The increase in unit pricing primarily resulted from market conditions associated with the extreme weather events in the first quarter of 2014, which included the polar vortex.
- Other operating expenses increased $369 million primarily resulting from higher costs at Regulated Distribution associated with network transmission expenses, increased vegetation management expenses in West Virginia, as well as higher operating and maintenance associated with reliability improvements, storm restoration costs and the Harrison/Pleasants

asset transfer. CES' increase in other operating expenses was primarily attributable to higher transmission costs, which resulted from the market conditions associated with the extreme weather events in the first quarter of 2014, and higher mark-to-market expenses on derivative contracts, partially offset by lower generation operating and maintenance costs primarily resulting from the deactivation of generating plants and the Harrison/Pleasants asset transfer.

FirstEnergy's other expenses decreased $121 million year-over-year, primarily resulting from the absence of a loss on debt redemptions of $124 million recognized in 2013. Higher interest expense was offset by higher investment income and capitalized financing costs, primarily attributable to Regulated Transmission's *Energizing the Future* investment plan.

FirstEnergy's effective tax rate on income from continuing operations was (24.6)% compared to 34.2% in 2013. The decrease in the effective tax rate was attributable to tax benefits recognized in 2014 associated with an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers and the expiration of the statute of limitations on uncertain tax positions. Additionally, during 2014, FirstEnergy recognized a reduction in income tax expense of $25 million that related to prior periods resulting from adjustments to its tax basis balance sheet.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 18, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

Net income by business segment was as follows:

				Increase (Decrease)	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 618	$ 465	$ 501	$ 153	$ (36)
Regulated Transmission	298	223	214	75	9
Competitive Energy Services	89	(331)	(218)	420	(113)
Corporate/Other [1]	(427)	(58)	(105)	(369)	47
Net Income	$ 578	$ 299	$ 392	$ 279	$ (93)
Basic Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)
Diluted Earnings Per Share:					
Continuing operations	$ 1.37	$ 0.51	$ 0.90	$ 0.86	$ (0.39)
Discontinued operations (Note 19)	—	0.20	0.04	(0.20)	0.16
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94	$ 0.66	$ (0.23)

[1] Consists primarily of interest on stand-alone holding company debt, none-core business related activity and corporate income taxes.

Summary of Results of Operations — 2015 Compared with 2014

Financial results for FirstEnergy's business segments in 2015 and 2014 were as follows:

2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,429	$ 1,011	$ 4,493	$ (173)	$ 14,760
Other	196	—	205	(135)	266
Internal	—	—	686	(686)	—
Total Revenues	9,625	1,011	5,384	(994)	15,026
Operating Expenses:					
Fuel	533	—	1,322	—	1,855
Purchased power	3,548	—	1,456	(686)	4,318
Other operating expenses	2,242	154	1,670	(317)	3,749
Pension and OPEB mark-to-market	179	3	60	—	242
Provision for depreciation	672	156	394	60	1,282
Amortization of regulatory assets, net	261	7	—	—	268
General taxes	703	102	140	33	978
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	8,146	422	5,076	(910)	12,734
Operating Income	1,479	589	308	(84)	2,292
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss)	42	—	(16)	(48)	(22)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	(586)	(161)	(192)	(193)	(1,132)
Capitalized financing costs	25	44	39	9	117
Total Other Expense	(519)	(117)	(169)	(594)	(1,399)
Income From Continuing Operations Before Income Taxes	960	472	139	(678)	893
Income taxes	342	174	50	(251)	315
Income From Continuing Operations	618	298	89	(427)	578
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$ 618	$ 298	$ 89	$ (427)	$ 578

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (Loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Impairment of equity method investment	—	—	—	—	—
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized financing costs	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

Changes Between 2015 and 2014 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 531	$ 242	$ (788)	$ 20	$ 5
Other	(8)	—	16	(36)	(28)
Internal	—	—	(133)	133	—
Total Revenues	523	242	(905)	117	(23)
Operating Expenses:					
Fuel	(34)	—	(391)	—	(425)
Purchased power	163	—	(694)	133	(398)
Other operating expenses	161	15	(405)	16	(213)
Pension and OPEB mark-to-market	(327)	1	(267)	—	(593)
Provision for depreciation	14	29	7	12	62
Amortization of regulatory assets, net	260	(4)	—	—	256
General taxes	10	32	(31)	5	16
Impairment of long-lived assets	8	—	34	—	42
Total Operating Expenses	255	73	(1,747)	166	(1,253)
Operating Income (Loss)	268	169	842	(49)	1,230
Other Income (Expense):					
Loss on debt redemptions	—	—	8	—	8
Investment income	(14)	—	(70)	(10)	(94)
Impairment of equity method investment	—	—	—	(362)	(362)
Interest expense	3	(30)	(3)	(29)	(59)
Capitalized financing costs	11	(11)	2	(3)	(1)
Total Other Expense	—	(41)	(63)	(404)	(508)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	268	128	779	(453)	722
Income taxes (benefits)	115	53	273	(84)	357
Income (Loss) From Continuing Operations	153	75	506	(369)	365
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income (Loss)	$ 153	$ 75	$ 420	$ (369)	$ 279

Regulated Distribution — 2015 Compared with 2014

Regulated Distribution's net income increased $153 million in 2015 compared to 2014, including a $327 million decrease in its Pension and OPEB mark-to-market adjustment. Excluding the impact of this adjustment, year-over-year earnings were impacted by increased operating expenses, including higher reliability maintenance expenses, higher benefit costs, and higher depreciation associated with increased capital investments, and a higher effective tax rate, partially offset by a net increase in new rates implemented in 2015 at certain operating companies.

Revenues —

The $523 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In millions)		
Distribution services	$ 3,993	$ 3,694	$ 299
Generation sales:			
Retail	4,303	4,043	260
Wholesale	508	661	(153)
Total generation sales	4,811	4,704	107
Transmission sales:			
Retail	513	352	161
Wholesale	112	148	(36)
Total transmission sales	625	500	125
Other	196	204	(8)
Total Revenues	$ 9,625	$ 9,102	$ 523

Distribution services revenues increased $299 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and for MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution services revenues increased resulting from the Ohio Companies' Rider DCR and higher cost recovery for above market NUG costs and certain energy efficiency programs for the Pennsylvania Companies, which was impacted by a rate increase in 2015. Partially offsetting these items were the impacts of lower residential and industrial customer usage as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	54,466	54,766	(0.5)%
Commercial	43,091	42,925	0.4 %
Industrial	50,269	51,276	(2.0)%
Other	585	586	(0.2)%
Total Electric Distribution MWH Deliveries	148,411	149,553	(0.8)%

Lower deliveries to residential customers, reflect declining weather-adjusted average customer usage due, in part, to increasing energy efficiency mandates as well as heating degree days that were 10.8% below the same period in 2014 and 2.8% below normal, partially offset by cooling degree days that were 32% above 2014 and 17% above normal. Commercial sales increased year-over-year from the increase in cooling degree days, partially offset by the lower heating degree days as well as decreased weather-adjusted usage due, in part, to increasing energy efficiency mandates. Deliveries to industrial customers decreased 2%, as the increase from shale and petroleum customer usage was more than offset by a decrease from steel and mining customer usage.

The following table summarizes the price and volume factors contributing to the $107 million increase in generation revenues in 2015 compared to 2014:

Source of Change in Generation Revenues		**Increase (Decrease)**
		(In millions)
Retail:		
Effect of increase in sales volumes	$	146
Change in prices		114
		260
Wholesale:		
Effect of decrease in sales volumes		(133)
Change in prices		(75)
Capacity revenue		55
		(153)
Increase in Generation Revenues	$	107

The increase in retail generation sales volume was primarily due to lower customer shopping in Ohio, Pennsylvania, and New Jersey and an increase in weather-related usage, partially offset by the impacts of energy efficiency as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 81% for the Ohio Companies, 65% from 67% for the Pennsylvania Companies and 50% from 52% for JCP&L. The increase in prices primarily resulted from higher default service auction results.

Wholesale generation revenues decreased $153 million in 2015 compared to 2014, primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch of fossil generating units associated with low spot market energy prices. Partially offsetting the decrease was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact on earnings.

The increase in retail transmission revenues of $161 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings. The decrease in wholesale transmission revenues of $36 million primarily relates to lower congestion revenue resulting from the impact of market conditions associated with the extreme weather and market conditions in 2014.

Operating Expenses —

Total operating expenses increased $255 million primarily due to the following:

- Fuel expense decreased $34 million in 2015 primarily related to lower economic dispatch resulting from low spot market energy prices.
- Purchased power costs were $163 million higher in 2015 primarily due to increased volumes reflecting lower customer shopping as described above, higher unit costs related to higher default service auction results, and higher capacity expense at MP, partially offset by lower purchases resulting from the termination of certain NUG contracts at JCP&L and PN.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 66
Change due to increased volumes	185
	251
Purchases from affiliates:	
Change due to decreased unit costs	(21)
Change due to decreased volumes	(113)
	(134)
Capacity expense	36
Amortization of deferred costs	10
Increase in Purchased Power Costs	$ 163

- Other operating expenses increased $161 million primarily due to:
  - Higher transmission expenses of $73 million primarily due to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The differences between current retail transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.
  - Increased regulated generation operating and maintenance expenses of $7 million, reflecting higher planned outage expenses in 2015 compared to 2014.
  - Higher retirement benefit costs of $22 million, reflecting higher net benefit costs before the pension and OPEB mark-to-market adjustment described below.
  - Higher distribution operating and maintenance expenses of $54 million, reflecting increased reliability maintenance in New Jersey and the Pennsylvania companies and other employee benefit costs, partially offset by lower storm restoration costs.
- Pension and OPEB mark-to-market adjustment decreased $327 million to $179 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.
- Depreciation expense increased $14 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L effective with the implementation of new rates from its distribution base rate case as well as lower depreciation rates in Pennsylvania based on updated asset life studies approved by the PPUC.
- Net regulatory asset amortization increased $260 million primarily due to:
  - Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($66 million),
  - Higher energy efficiency program cost recovery ($66 million),
  - Lower deferral of TTS costs in West Virginia ($37 million),
  - Higher amortizations of above-market NUG costs in Pennsylvania and New Jersey ($36 million),
  - Lower deferral of West Virginia vegetation management expenses ($31 million),
  - Higher default generation service cost amortization ($28 million), and
  - Recovery of Pennsylvania legacy meter costs ($22 million); partially offset by
  - Higher cost deferral of Ohio network transmission expenses ($33 million).
- General taxes increased $10 million primarily due to higher revenue-related taxes in Pennsylvania, partially offset by lower property taxes in Ohio.

Other Expense —

Other expense was flat in 2015 as compared to 2014, as lower investment income was offset by lower interest expense and higher capitalized financing costs.

Income Taxes —

Regulated Distribution's effective tax rate was 35.6% and 32.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Regulated Transmission — 2015 Compared with 2014

Net income increased $75 million in 2015 compared to 2014. Higher Transmission revenues associated with ATSI's "forward looking" rate and higher rate base were partially offset by higher interest expense and lower capitalized financing costs.

Revenues —

Total revenues increased $242 million principally at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2015	2014	Increase
		(In millions)	
ATSI	$ 446	$ 242	$ 204
TrAIL	252	214	38
PATH	13	13	—
Utilities	300	300	—
Total Revenues	$ 1,011	$ 769	$ 242

Operating Expenses —

Total operating expenses increased $73 million principally due to higher operating and maintenance expenses, depreciation, and property taxes at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expenses —

Other expenses increased $41 million due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings as well as lower capitalized financing costs.

Income Taxes —

Regulated Transmission's effective tax rate was 36.9% and 35.2% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

CES — 2015 Compared with 2014

Operating results increased $420 million in 2015 compared to 2014, primarily from higher capacity revenues and the absence of the impact of the high market prices associated with extreme weather events and unplanned outages in 2014 that resulted in higher purchased power and transmission costs, partially offset by lower contract sales volumes. Additionally, changes in year-over-year operating results were impacted by lower Pension and OPEB mark-to-market adjustments, lower settlement and termination costs related to coal and transportation contracts, and the absence of a $78 million after-tax gain on the sale of certain hydroelectric facilities recognized in February 2014.

Revenues —

Total revenues decreased $905 million in 2015, compared to 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing as well as higher capacity revenues, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$ 1,269	$ 2,359	$ (1,090)
Governmental Aggregation	1,012	1,184	(172)
Mass Market	265	452	(187)
POLR	712	902	(190)
Structured Sales	558	522	36
Total Contract Sales	3,816	5,419	(1,603)
Wholesale	1,225	461	764
Transmission	138	220	(82)
Other	205	189	16
Total Revenues	$ 5,384	$ 6,289	$ (905)

MWH Sales by Channel	For the Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	23,585	44,012	(46.4)%
Governmental Aggregation	15,443	19,569	(21.1)%
Mass Market	3,878	6,773	(42.7)%
POLR	11,950	15,708	(23.9)%
Structured Sales	12,902	12,814	0.7 %
Total Contract Sales	67,758	98,876	(31.5)%
Wholesale	7,326	680	977.4 %
Total MWH Sales	75,084	99,556	(24.6)%

The following tables summarize the price and volume factors contributing to changes in revenues:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	**Sales Volumes**	**Prices**	**Gain on Settled Contracts**	**Capacity Revenue**	**Total**
	(In millions)				
Direct	$ (1,095)	$ 5	$ —	$ —	$ (1,090)
Governmental Aggregation	(249)	77	—	—	(172)
Mass Market	(193)	6	—	—	(187)
POLR	(216)	26	—	—	(190)
Structured Sales	3	33	—	—	36
Wholesale	197	(8)	107	468	764

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflect CES' efforts to more effectively hedge its generation by reducing exposure to weather-sensitive load. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price, partially offset by a lower energy component of the retail price resulting from lower year-over-year market prices. The Direct, Governmental Aggregation and Mass Market customer base was 1.6 million as of December 31, 2015, compared to 2.1 million as of December 31, 2014.

The decrease in POLR sales of $190 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $36 million due to low market prices that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $764 million primarily due to an increase in capacity revenue from higher capacity prices, increase in short-term (net hourly position) transactions, and higher net gains on financially settled contracts, partially offset by lower spot market energy prices which limited additional wholesale sales.

Transmission revenue decreased $82 million primarily due to lower congestion revenue resulting from the market conditions associated with the extreme weather events in 2014.

Other revenue increased $16 million primarily due to higher lease revenues from additional equity interests in affiliated sale and leasebacks repurchased in November 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,747 million in 2015 due to the following:

- Fuel costs decreased $391 million primarily due to lower economic dispatch of fossil units resulting from low spot market energy prices and lower nuclear unit prices, resulting from the suspension of the DOE nuclear disposal fee, effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. The impact of terminations and settlements of coal and transportation contracts resulted in a pre-tax loss of $67 million and $166 million in 2015 and 2014, respectively.

- Purchased power costs decreased $694 million due to lower volumes ($888 million), partially offset by higher unit prices ($39 million) and higher capacity expenses ($155 million). Lower volumes were primarily due to decreased load requirements resulting from lower sales as discussed above, partially offset by lower fossil generation as discussed above. The higher unit prices are primarily due to higher losses on financially settled contracts, partially offset by lower market prices in 2015 as compared to 2014. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Nuclear operating costs increased $84 million as a result of higher planned outage costs and higher employee benefit expenses. There were three planned refueling outages in 2015 as compared to two planned outages in 2014.

- Transmission expenses decreased $273 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in 2014.

- General taxes decreased $31 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Pension and OPEB mark-to-market adjustment decreased $267 million to $60 million, which was impacted by lower than expected asset returns, partially offset by an increase in the discount rate used to measure benefit obligations.

- Other operating expenses decreased $212 million primarily due to a $141 million decrease in mark-to-market expenses on commodity contract positions reflecting lower market prices and a $71 million decrease in retail-related costs.

- Impairments of long-lived assets increased $34 million due to impairment charges associated with non-core assets.

Other Expense —

Total other expense increased $63 million in 2015 compared to 2014 primarily due to higher OTTI on NDT investments, partially offset by the absence of an $8 million loss on debt redemptions incurred in 2014.

Discontinued Operations —

There were no discontinued operations in 2015. In 2014, discontinued operations primarily included a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of certain hydroelectric assets on February 12, 2014.

Income Taxes (Benefits) —

CES' effective tax rate was 36.0% and 34.8% for 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Corporate/Other — 2015 Compared with 2014

Financial results from Corporate/Other resulted in a $369 million decrease in net income in 2015 compared to 2014 primarily due to a $362 million pre-tax impairment of FirstEnergy's equity method investment in Global Holding, higher costs associated with environmental remediation at legacy plants, higher interest expense and a higher effective tax rate. During 2015, based on the significant decline in coal pricing and the current outlook for the coal market, FirstEnergy assessed the carrying value of its investment in Global Holding and determined there was an other than temporary decline in the fair value below its carrying value, which resulted in the impairment charge. The increased interest expense primarily relates to a $1 billion term loan entered into in March 2014 and a gain on the termination of interest rate swap arrangements recognized in 2014. The higher effective tax rate primarily resulted from the absence of tax benefits recognized in 2014 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, the elimination of certain tax liabilities associated with basis differences as well as certain tax benefits recorded in 2014 that related to prior periods.

Summary of Results of Operations — 2014 Compared with 2013

Financial results for FirstEnergy's business segments in 2014 and 2013 were as follows:

2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,898	$ 769	$ 5,281	$ (193)	$ 14,755
Other	204	—	189	(99)	294
Internal	—	—	819	(819)	—
Total Revenues	9,102	769	6,289	(1,111)	15,049
Operating Expenses:					
Fuel	567	—	1,713	—	2,280
Purchased power	3,385	—	2,150	(819)	4,716
Other operating expenses	2,081	139	2,075	(333)	3,962
Pension and OPEB mark-to-market	506	2	327	—	835
Provision for depreciation	658	127	387	48	1,220
Amortization of regulatory assets, net	1	11	—	—	12
General taxes	693	70	171	28	962
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	7,891	349	6,823	(1,076)	13,987
Operating Income (loss)	1,211	420	(534)	(35)	1,062
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	56	—	54	(38)	72
Interest expense	(589)	(131)	(189)	(164)	(1,073)
Capitalized interest	14	55	37	12	118
Total Other Expense	(519)	(76)	(106)	(190)	(891)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	692	344	(640)	(225)	171
Income taxes (benefits)	227	121	(223)	(167)	(42)
Income (Loss) From Continuing Operations	465	223	(417)	(58)	213
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 465	$ 223	$ (331)	$ (58)	$ 299

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 731	$ 5,542	$ (161)	$ 14,611
Other	221	—	186	(126)	281
Internal	—	—	770	(770)	—
Total Revenues	8,720	731	6,498	(1,057)	14,892
Operating Expenses:					
Fuel	377	—	2,119	—	2,496
Purchased power	3,308	—	1,425	(770)	3,963
Other operating expenses	1,773	131	2,007	(318)	3,593
Pension and OPEB mark-to-market	(149)	—	(107)	—	(256)
Provision for depreciation	606	114	439	43	1,202
Amortization of regulatory assets, net	529	10	—	—	539
General taxes	697	54	202	25	978
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	7,463	309	6,558	(1,020)	13,310
Operating Income (Loss)	1,257	422	(60)	(37)	1,582
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	14	(38)	33
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized interest	31	14	42	16	103
Total Other Expense	(455)	(79)	(315)	(163)	(1,012)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	802	343	(375)	(200)	570
Income taxes (benefits)	301	129	(140)	(95)	195
Income From Continuing Operations	501	214	(235)	(105)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	$ 501	$ 214	$ (218)	$ (105)	$ 392

Changes Between 2014 and 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 399	$ 38	$ (261)	$ (32)	$ 144
Other	(17)	—	3	27	13
Internal	—	—	49	(49)	—
Total Revenues	382	38	(209)	(54)	157
Operating Expenses:					
Fuel	190	—	(406)	—	(216)
Purchased power	77	—	725	(49)	753
Other operating expenses	308	8	68	(15)	369
Pension and OPEB mark-to-market	655	2	434	—	1,091
Provision for depreciation	52	13	(52)	5	18
Amortization of regulatory assets, net	(528)	1	—	—	(527)
General taxes	(4)	16	(31)	3	(16)
Impairment of long-lived assets	(322)	—	(473)	—	(795)
Total Operating Expenses	428	40	265	(56)	677
Operating Income (Loss)	(46)	(2)	(474)	2	(520)
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(17)	124
Investment income	(1)	—	40	—	39
Interest expense	(46)	(38)	33	(6)	(57)
Capitalized interest	(17)	41	(5)	(4)	15
Total Other Expense	(64)	3	209	(27)	121
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	(110)	1	(265)	(25)	(399)
Income taxes (benefits)	(74)	(8)	(83)	(72)	(237)
Income (Loss) From Continuing Operations	(36)	9	(182)	47	(162)
Discontinued Operations, net of tax	—	—	69	—	69
Net Income (Loss)	$ (36)	$ 9	$ (113)	$ 47	$ (93)

Regulated Distribution — 2014 Compared with 2013

Regulated Distribution's net income decreased $36 million in 2014 compared to 2013. Regulated Distribution's Pension and OPEB mark-to-market adjustment increased $655 million which was partially offset by a reduction in regulatory asset impairment charges of $305 million and an impairment of long-lived assets of $322 million incurred in 2013. Excluding the impact of these charges, year-over-year earnings were impacted by higher distribution operating and maintenance costs, including the impact of higher benefit costs, higher depreciation and property taxes, and higher interest expense from debt issuances. These items were partially offset by slightly higher distribution deliveries, higher earnings associated with the October 2013 Harrison/Pleasants asset transfer, and a lower effective tax rate.

Revenues —

The $382 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,694	$ 3,762	$ (68)
Generation sales:			
Retail	4,043	3,959	84
Wholesale	661	330	331
Total generation sales	4,704	4,289	415
Transmission sales:			
Retail	352	347	5
Wholesale	148	101	47
Total transmission sales	500	448	52
Other	204	221	(17)
Total Revenues	$ 9,102	$ 8,720	$ 382

The decrease in distribution services revenue is primarily related to a decrease in revenues from ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013 and a rider rate decrease associated with the recovery of energy efficiency and other customer program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries of 1.1% as described below, rate increases for the Ohio Companies associated with energy efficiency performance shared savings and the Rider DCR, and higher revenues for the Pennsylvania Companies associated with the recovery of Smart Meter program costs. Certain Ohio energy efficiency programs permit the Ohio Companies to bill and collect shared savings revenues if energy efficiency programs meet or exceed the state mandates. Additionally, the Rider DCR provides for recovery of incremental operating expenses and a return on rate base associated with incremental distribution plant investments in Ohio. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2014	2013	Increase
	(In thousands)		
Residential	54,766	54,479	0.5%
Commercial	42,925	42,582	0.8%
Industrial	51,276	50,243	2.1%
Other	586	584	0.3%
Total Electric Distribution MWH Deliveries	149,553	147,888	1.1%

Higher deliveries to residential customers primarily reflect increased weather-related usage resulting from heating degree days that were 7% above 2013, and 9% above normal, partially offset by cooling degree days that were 15% below 2013, and 12% below normal. Increased deliveries to commercial customers reflect improving economic conditions across FirstEnergy's service territories. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical and paper customers.

The following table summarizes the price and volume factors contributing to the $415 million increase in generation revenues in 2014 compared to 2013:

Source of Change in Generation Revenues	Increase (In millions)
Retail:	
Effect of increase in sales volumes	$ 14
Change in prices	70
	84
Wholesale:	
Effect of increase in sales volumes	166
Change in prices	79
Capacity revenue	86
	331
Increase in Generation Revenues	$ 415

The increase in retail generation sales volume was primarily due to weather-related usage, as described above, and improving economic conditions, partially offset by increased customer shopping in Pennsylvania. The increase in retail generation prices reflects higher Pennsylvania PTC prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact on retail generation prices of MP's Temporary Transaction Surcharge (TTS) associated with the October 2013 Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs. As part of the TTS, MP earns a return on and of the Harrison plant costs.

The increase in wholesale generation revenues of $331 million in 2014 resulted from increased volume and energy prices associated with market conditions related to extreme weather events in January 2014 and increased capacity revenue related to the October 2013 Harrison/Pleasants asset transfer whereby MP acquired from AE Supply 1,476 MWs of net capacity. During January 2014, unprecedented customer demand associated with prolonged periods of bitterly cold temperatures and unit unavailability across the PJM footprint resulted in severe market price volatility for electricity and natural gas throughout PJM. Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. The difference between wholesale generation revenues, primarily associated with MP's regulated generation, and certain energy costs are deferred for future recovery, with no material impact to earnings.

The increase in transmission revenues of $52 million reflects higher PJM revenues at MP associated with market conditions related to extreme weather events described above and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013 as discussed above. Network transmission costs are now recovered through WP's generation rate.

Other revenues decreased $17 million primarily due to less customer requested work in 2014 compared to 2013.

Operating Expenses —

Total operating expenses increased by $428 million primarily due to the following:

- Fuel expense was $190 million higher in 2014 primarily related to increased generation as a result of the October 2013 Harrison/Pleasants asset transfer.
- Purchased power costs were $77 million higher in 2014 primarily due to increased unit prices and capacity expense reflecting higher auction clearing prices, partially offset by a decrease in purchased volumes required.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 127
Change due to decreased volumes	(134)
	(7)
Purchases from affiliates:	
Change due to increased unit costs	39
Change due to increased volumes	2
	41
Capacity expense	58
Increase in costs deferred	(15)
Increase in Purchased Power Costs	$ 77

Other operating expenses increased $308 million primarily due to:

- Higher transmission expenses of $130 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of market conditions related to extreme weather events in January 2014 and higher PJM transmission costs resulting from the October 2013 Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.

- Higher distribution operating and maintenance expenses of $75 million resulting from higher maintenance activities and storm related restoration expenses, including $26 million of storm expenses deferred for future recovery.

- Higher vegetation management expenses in West Virginia of $33 million, which were deferred for future recovery per authorization of the WVPSC.

- Higher retirement benefit costs of $33 million primarily reflecting higher net periodic benefit costs before the pension and OPEB mark-to-market adjustments discussed below.

- Increased regulated generation operating and maintenance expenses of $23 million, reflecting increased costs associated with the October 2013 Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Pension and OPEB mark-to-market adjustments increased $655 million to $506 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.

- Depreciation expense increased $52 million due to a higher asset base, including $22 million at MP associated with the October 2013 Harrison/Pleasants asset transfer.

- Net regulatory asset amortization decreased $528 million primarily due to:
  - Impairment charges on regulatory assets of $305 million associated with the recovery of marginal transmission losses at ME and PN ($254 million) and the recovery of RECs for the Ohio Companies ($51 million) that occurred in 2013,
  - Decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies ($67 million),
  - Lower default generation service and NUG costs recovery in Pennsylvania ($48 million),
  - Increased deferral of West Virginia vegetation management expenses ($33 million) and customer refunds associated with the gain on the Pleasants plant resulting from the October 2013 Harrison/Pleasants asset transfer ($36 million), and
  - Higher storm cost deferrals ($26 million).

- General taxes decreased $4 million primarily due to lower revenue-related taxes, partially offset by higher property taxes and an increase in the West Virginia business and occupation tax as a result of the October 2013 Harrison/Pleasants asset transfer.

- The 2013 impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of the Harrison plant to the amount permitted to be included in rate base as part of the October 2013 Harrison/Pleasants asset transfer.

Other Expense —

Other expense increased $64 million in 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the October 2013 Harrison/Pleasants asset transfer, a new debt issuance of $500 million in August 2013 at JCP&L and lower capitalized financing costs related primarily to a decrease in the rate used for borrowed funds.

Income Taxes —

Regulated Distribution's effective tax rate was 32.8% and 37.5% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in state flow through income tax benefits and other realized tax benefits.

Regulated Transmission — 2014 Compared with 2013

Net income increased $9 million in 2014 compared to 2013. Higher Transmission revenues associated with increased capital investments and higher capitalized financing costs were partially offset by higher operating expenses and interest expense.

Revenues —

Total revenues increased $38 million principally due to higher revenue at ATSI and TrAIL, reflecting recovery of incremental operating expenses and a higher rate base as included in their annual rate filings effective June 2013 and June 2014.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
ATSI	$ 242	$ 209	$ 33
TrAIL	214	207	7
PATH	13	20	(7)
Utilities	300	295	5
Total Revenues	$ 769	$ 731	$ 38

Operating Expenses —

Total operating expenses increased $40 million principally due to higher property taxes, depreciation and other operating expenses.

Other Expenses —

Total other expenses decreased $3 million principally due to higher capitalized financing costs of $41 million related to increased construction work in progress balances associated with the *Energizing the Future* investment plan, partially offset by increased interest expense resulting from new debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings.

Income Taxes —

Regulated Transmission's effective tax rate was 35.2% and 37.6% for 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from an increase in AFUDC equity flow through.

CES — 2014 Compared with 2013

Operating results decreased $113 million in 2014, compared to 2013. Lower impairment charges of $473 million associated with the deactivation of the Hatfield and Mitchell generating units and a lower loss on debt redemptions of $141 million were partially offset with higher Pension and OPEB mark-to-market adjustments of $434 million. Excluding the impact of these charges, year-over-year earnings were impacted by lower sales volumes, reflecting CES' selling efforts discussed below and an increase in purchased power and transmission costs incurred to serve contract sales due to market conditions associated with the extreme weather events in January 2014. Partially offsetting these items were lower operating expenses due to lower retail-related costs, lower generation costs resulting from plant deactivations and asset transfers, and higher capacity revenues from higher auction prices. Additionally, operating results were impacted by a $78 million after-tax gain on the sale of certain hydro facilities in February 2014.

Revenues —

Total revenues decreased $209 million in 2014, compared to 2013, primarily due to decreased sales volumes in the Direct and Governmental Aggregation sales channels, partially offset by higher volume in the Structured Sales channel. Revenues were also impacted by higher unit prices as a result of increased channel pricing and higher capacity revenues, as described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2014	2013	Increase (Decrease)
		(In millions)	
Contract Sales:			
Direct	$ 2,359	$ 2,913	$ (554)
Governmental Aggregation	1,184	1,185	(1)
Mass Market	452	448	4
POLR	902	858	44
Structured Sales	522	421	101
Total Contract Sales	5,419	5,825	(406)
Wholesale	461	343	118
Transmission	220	144	76
Other	189	186	3
Total Revenues	$ 6,289	$ 6,498	$ (209)

MWH Sales by Channel	For the Years Ended December 31, 2014	2013	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	44,012	56,145	(21.6)%
Governmental Aggregation	19,569	20,859	(6.2)%
Mass Market	6,773	6,761	0.2 %
POLR	15,708	15,758	(0.3)%
Structured Sales	12,814	9,047	41.6 %
Total Contract Sales	98,876	108,570	(8.9)%
Wholesale	680	1,250	(45.6)%
Total MWH Sales	99,556	109,820	(9.3)%

The following tables summarize the price and volume factors contributing to changes in revenues:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (629)	$ 75	$ —	$ —	$ (554)
Governmental Aggregation	(73)	72	—	—	(1)
Mass Market	1	3	—	—	4
POLR	(3)	47	—	—	44
Structured Sales	176	(75)	—	—	101
Wholesale	(17)	—	(21)	156	118

Lower sales volumes in the Direct, Governmental Aggregation and Mass Market sales channels primarily reflects CES' efforts to more effectively hedge its generation by reducing exposure to weather sensitive load. Additionally, although unit pricing was higher year-over-year in the Direct, Governmental Aggregation and Mass Market channels noted above, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase in prices associated with capacity was partially offset by lower energy pricing built into the retail product at the time customers were acquired for 2014 sales. Beginning in the fourth quarter of 2011, when there was a significant decline in energy prices, CES' 2014 retail sales position was approximately 30% committed, whereas its 2013 retail sales position was approximately 60% committed, resulting in a greater proportion of 2014 sales and unit prices being impacted by the decline in the energy prices.

The increase in POLR revenues of $44 million was due to higher rates associated with the capacity expense component of the rate discussed above, partially offset by lower sales volumes. The increase in Structured Sales revenues of $101 million was due to higher sales volumes, partially offset by lower unit prices primarily due to market conditions related to extreme weather events in 2014 that reduced the gains on various structured financial sales contracts.

Wholesale revenues increased $118 million primarily due to an increase in capacity revenue from higher capacity prices, partially offset by a decrease in short-term (net hourly positions) transactions. The decrease in Wholesale sales volumes was due to lower generation available to sell primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013.

Transmission revenue increased $76 million due to higher congestion revenue driven by market conditions related to extreme weather events in 2014, as discussed above.

Other revenue increased $3 million in 2014 as compared to 2013 as higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since 2013, partially offset by a $17 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate. CES earns lease revenue associated with the equity interests it has purchased.

Operating Expenses —

Total operating expenses increased $265 million in 2014 due to the following:

- Fuel costs decreased $406 million primarily due to lower generation volumes resulting from the October 2013 Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and increased outages as compared to the same period of 2013. Higher unit prices, primarily driven by increased peaking generation, was partially offset by the suspension of the DOE nuclear disposal fee, which was effective May 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. Terminations and settlements associated with damages on coal and transportation contracts were approximately $166 million and $128 million in 2014 and 2013, respectively.

- Purchased power costs increased $725 million due to higher volumes ($252 million), increased unit prices ($565 million) and higher capacity expenses ($311 million), partially offset by lower losses on financially settled contracts ($403 million). Higher purchased volumes were primarily due to lower available generation due to outages, the October 2013 Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by lower contract sales as described above. The increase in unit prices was primarily a result of market conditions related to extreme weather events in January 2014, partially offset by lower losses on financially settled contracts. The increase in capacity expense, which is a component of the segment's retail price, was primarily the result of higher capacity rates associated with the segment's retail sales obligations.

- Fossil operating costs decreased $73 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the October 2013 Harrison/Pleasants asset transfer.
- Nuclear operating costs increased $6 million as a result of higher labor, contractor, materials and equipment costs. There were two refueling outages in each of 2014 and 2013, however, the duration of the outages in 2014 exceeded the prior year.
- Transmission expenses increased $80 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in 2014. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.
- General taxes decreased $31 million primarily due to lower gross receipts taxes resulting from reduced retail sales volumes, lower payroll taxes as a result of lower labor costs noted above, lower property taxes due to the October 2013 Harrison/Pleasants asset transfer, and reduced Ohio personal property taxes.
- Impairments of long-lived assets decreased $473 million due to the impairment of two unregulated, coal-fired generating plants recognized in 2013.
- Depreciation expense decreased $52 million primarily due to a reduction in the asset base as a result of the plant deactivations and the October 2013 Harrison/Pleasants asset transfer noted above.
- Pension and OPEB mark-to-market adjustments increased $434 million to $327 million, primarily reflecting a lower discount rate and revisions to mortality assumptions extending the expected life in key demographics used to measure related obligations in 2014.
- Other operating expenses increased $55 million primarily due to an increase in mark-to-market expenses on commodity contract positions, and an impairment of deferred advertising costs of $23 million associated with the elimination of future selling efforts in the Mass Market and certain Direct sales channels, partially offset by lower retail and marketing related costs.

Other Expense —

Total other expense in 2014 decreased $209 million compared to 2013 due to the absence of a $141 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, higher investment income primarily on the NDT investments, lower OTTI and lower net interest expense of $28 million due to debt redemptions.

Income Tax Benefits —

CES' effective tax rate was 34.8% and 37.3% for 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pre-tax losses, primarily resulted from changes in state apportionment factors and higher valuation allowances on certain NOL carryforwards.

Discontinued Operations —

Discontinued operations increased $69 million in 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of hydro assets in February 2014.

Corporate/Other — 2014 Compared with 2013

Financial results from Corporate/Other resulted in a $47 million increase in net income in 2014 compared to 2013 primarily due to higher tax benefits, partially offset by $17 million of gains on debt redemptions in 2013. The higher tax benefits primarily resulted from an IRS-approved change in accounting method that increased the tax basis of certain assets resulting in higher future tax deductions, and the resolution of state tax benefits resulting from the expiration of the statute of limitation on certain state tax positions. Additional income tax benefits of $25 million were recognized in 2014 that relate to prior periods. The out-of-period adjustment primarily related to the correction of amounts included on FirstEnergy's tax basis balance sheet. Management has determined that these adjustments are not material to the current or any prior period. The 2013 effective tax rate benefited from reductions to valuation allowances against state NOL carryforwards, as well as changes in state apportionment factors, which reduced deferred tax liabilities.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets (Liabilities) by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest payments, dividend payments, and contributions to its pension plan. During 2015, FirstEnergy received $630 million of cash dividends and capital returned from its subsidiaries and paid $607 million in cash dividends to common shareholders. In addition to internal sources to fund liquidity and capital requirements for 2016 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

Additionally in 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

FirstEnergy's longer term strategic outlook for its regulated and competitive businesses will be determined following resolution of the Ohio Companies' ESP IV, including the proposed PPA between FES and the Ohio Companies. Once the ESP IV is finalized, FirstEnergy expects to be in a position to more fully understand the longer-term outlook of its competitive businesses and the longer term growth rate of its regulated businesses, including planned capital investments and any additional equity to fund growth in its regulated businesses. With the exception of Regulated Transmission's 2016 projected capital expenditures discussed below, planned capital expenditures for 2016 for Regulated Distribution, CES, and Corporate/Other will depend on the outcome of the Ohio Companies' ESP IV and remain subject to Board approval.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion *Energizing the Future* investment plan that began in 2014 and will continue through 2017 to upgrade and expand FirstEnergy's transmission system. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. In total, FirstEnergy has identified at least $15 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

In alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments and the repositioning of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at each business unit, and maintaining strong liquidity for an overall stable financial position. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

As part of an ongoing effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three-year period.

Any financing plans by FirstEnergy, including the issuance of equity, refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such issuances, financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of December 31, 2015, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2015, included the following:

Currently Payable Long-Term Debt	***(In millions)***
PCRBs supported by bank LOCs [(1)]	$ 92
FMBs	245
Unsecured notes	300
Unsecured PCRBs [(1)]	391
Collateralized lease obligation bonds	23
Sinking fund requirements	87
Other notes	28
	$ 1,166

(1) These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings / Revolving Credit Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[(1)]	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET[(2)]	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2015:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
		(In millions)		
FE	$ 3,500	$ —	$ —	$ — [1]
FES	—	1,500	—	— [2]
AE Supply	—	1,000	—	— [2]
FET	—	—	1,000	— [1]
OE	500	—	—	500 [3]
CEI	500	—	—	500 [3]
TE	500	—	—	500 [3]
JCP&L	600	—	—	500 [3]
ME	300	—	—	500 [3]
PN	300	—	—	300 [3]
WP	200	—	—	200 [3]
MP	500	—	—	500 [3]
PE	150	—	—	150 [3]
ATSI	—	—	500	500 [3]
Penn	50	—	—	100 [3]
TrAIL	—	—	400	400 [3]

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of December 31, 2015 were issued by the following bank:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	$ 92	March 2017	March 2017

(1) Excludes approximately $1 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of December 31, 2015:

	Senior Secured		Senior Unsecured		
Issuer	**S&P**	**Moody's**	**S&P**	**Moody's**	**Fitch**
FE	—	—	BB+	Baa3	BB+
FES	BBB-	—	BBB-	Baa3	—
AE Supply	BBB-	—	BBB-	Baa3	—
AGC	—	—	BBB-	Baa3	—
ATSI	—	—	BBB-	Baa2	—
CEI	BBB+	Baa1	BBB-	Baa3	—
FET	—	—	BB+	Baa3	
JCP&L	—	—	BBB-	Baa2	—
ME	—	—	BBB-	Baa1	—
MP	BBB+	A3	—	—	—
OE	BBB+	A2	BBB-	Baa1	—
PN	—	—	BBB-	Baa2	—
Penn	—	A2	—	—	—
PE	BBB+	A3	—	—	—
TE	BBB	Baa1	—	—	—
TrAIL	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2015, FE and its subsidiaries could issue additional debt of approximately $5.1 billion and remain within the limitations of the financial covenants required by the Facilities. As of December 31, 2015, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.1 billion given FE's consolidated debt to total capitalization ratio under the FE Facility.

Changes in Cash Position

As of December 31, 2015, FirstEnergy had $131 million of cash and cash equivalents compared to $85 million of cash and cash equivalents as of December 31, 2014. As of December 31, 2015 and 2014, FirstEnergy had approximately $82 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are derived from electric services provided by its utility operating subsidiaries and the sale of energy and related products and services by its unregulated competitive subsidiaries. The most significant use of cash from operating activities is to buy electricity in the wholesale market and pay fuel suppliers, interest, employees, tax authorities, lenders and others for a wide range of materials and services.

Net cash provided from operating activities was $3,447 million during 2015, $2,713 million during 2014 and $2,662 million during 2013. Cash flows from operations increased $734 million in 2015 compared with 2014 due to the following:

- Distribution rate increases associated with the implementation of new rates, partially offset by a year-over-year decline in distribution deliveries;
- Higher transmission revenue and earnings, reflecting recovery of incremental operating expenses, a higher rate base and forward-looking rates at ATSI;
- Higher capacity revenues at CES, partially offset by a decline in sales volume;
- Lower disbursements for fuel and purchased power resulting from the lower sales volumes; and
- Lower posted collateral; partially offset by,
- A $143 million contribution to the qualified pension plan in 2015.

Cash Flows From Financing Activities

In 2015, cash used for financing activities was $279 million compared to $513 million and $477 million of net cash provided from financing activities during 2014 and 2013, respectively. The following table summarizes new debt financing (net of any discounts), redemptions and common stock dividend payments:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	**2015**	**2014**	**2013**
		(In millions)	
New Issues			
Unsecured notes	$ 475	$ 2,400	$ 2,300
PCRBs	339	878	—
FMBs	295	200	1,000
Term loan	200	1,050	—
Senior secured notes	2	—	445
	$ 1,311	$ 4,528	$ 3,745
Redemptions / Repayments			
Unsecured notes	$ —	$ (600)	$ (2,284)
PCRBs	(313)	(793)	(470)
FMBs	(215)	(175)	(420)
Term loan	(200)	—	—
Senior secured notes	(151)	(191)	(376)
Long-term revolving credit	—	—	(50)
	$ (879)	$ (1,759)	$ (3,600)
Tender premiums paid on debt redemptions	$ —	$ —	$ (110)
Short-term borrowings, net	$ (91)	$ (1,605)	$ 1,435
Common stock dividend payments	$ (607)	$ (604)	$ (920)

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

Cash Flows From Investing Activities

Cash used for investing activities in 2015 principally represented cash used for property additions. The following table summarizes investing activities for 2015, 2014 and 2013:

	For the Years Ended December 31,		
Cash Used for Investing Activities	**2015**	**2014**	**2013**
		(In millions)	
Property Additions:			
Regulated distribution	$ 1,108	$ 972	$ 1,272
Regulated transmission	952	1,329	461
Competitive energy services	588	939	827
Other and reconciling adjustments	56	72	78
Nuclear fuel	190	233	250
Proceeds from asset sales	(20)	(394)	(4)
Investments	107	68	72
Asset removal costs	142	153	146
Other	(1)	(13)	(9)
	$ 3,122	$ 3,359	$ 3,093

Cash used for investing activity in 2015 as compared to 2014 were impacted by lower property additions of $608 million, partially offset by a $374 million reduction in proceeds received from asset sales, as 2014 included proceeds from the sale of certain hydroelectric assets. The decline in property additions were due to the following:

- a decrease of $351 million at CES, resulting from the absence of capital investments associated with the Davis-Besse steam generators that were placed into service in May 2014,
- a decrease of $377 million at Regulated Transmission primarily relating to the timing of capital investments associated with its *Energizing the Future* investment program, partially offset by
- an increase of $136 million at Regulated Distribution relating to utility specific project investments and costs associated with the Pennsylvania smart meter program.

CONTRACTUAL OBLIGATIONS

As of December 31, 2015, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2016	2017-2018	2019-2020	Thereafter
			(In millions)		
Long-term debt(1)	$ 20,238	$ 1,039	$ 3,435	$ 3,499	$ 12,265
Short-term borrowings	1,708	1,708	—	—	—
Interest on long-term debt(2)	12,523	1,015	1,839	1,500	8,169
Operating leases(3)	2,083	184	254	207	1,438
Capital leases(3)	150	36	55	32	27
Fuel and purchased power(4)	13,578	1,812	2,539	2,117	7,110
Capital expenditures (5)	2,213	877	938	398	—
Pension funding	3,564	381	1,122	787	1,274
Total	$ 56,057	$ 7,052	$ 10,182	$ 8,540	$ 30,283

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and capital leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2015.
(3) See Note 6, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Amounts represent committed capital expenditures as of December 31, 2015.

Excluded from the table above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $3.5 billion in 2016, $0.5 billion of which are expected to relate to the Utilities' contracts with FES.

The table above also excludes regulatory liabilities (see Note 14, Regulatory Matters), AROs (see Note 13, Asset Retirement Obligations), reserves for litigation, injuries and damages, environmental remediation, and annual insurance premiums, including nuclear insurance (see Note 15, Commitments, Guarantees and Contingencies) since the amount and timing of the cash payments are uncertain. The table also excludes accumulated deferred income taxes and investment tax credits since cash payments for income taxes are determined based primarily on taxable income for each applicable fiscal year.

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $15 million (NG-$15.1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $83 million (NG-$81 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2015, was approximately $3.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[(1)]	$ 33
Deferred compensation arrangements	533
Other[(2)]	17
	583
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[(3)]	251
FES' guarantee of NG's nuclear property insurance	98
FES' guarantee of nuclear decommissioning costs	21
FES' guarantee of FG's sale and leaseback obligations	1,767
	2,137
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	398
Surety Bonds	22
FES' LOC (long-term tax-exempt debt)[(4)]	93
LOCs[(5)]	154
	667
Total Guarantees and Other Assurances	$ 3,687

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.
(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $7 million for railcar leases, and $6 million for various leases.
(3) Includes energy and energy-related contracts associated with FES of approximately $248 million.
(4) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.
(5) Includes $54 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $88 million issued in connection with energy and energy related contracts, $2 million issued in connection with railcar leases, $7 million pledged in connection with the sale and leaseback of the Beaver Valley Unit 2 by OE and $3 million pledged in connection with the sale and leaseback of Perry by OE.

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2015:

Collateral Provisions	**FES**	**AE Supply**	**Utilities**	**Total**
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $8 million with affiliated parties.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $950 million as of December 31, 2015 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. In November 2014, NG repurchased lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative assets and liabilities as of December 31, 2015 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$ (6)	$ 1	$ —	$ —	$ —	$ —	$ (5)
Other external sources[2]	18	(1)	(21)	(26)	—	—	(30)
Prices based on models	(4)	2	—	—	(7)	—	(9)
Total[3]	$ 8	$ 2	$ (21)	$ (26)	$ (7)	$ —	$ (44)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(136) million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts as of December 31, 2015, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next 12 months.

Equity Price Risk

As of December 31, 2015, the FirstEnergy pension and OPEB plan assets were approximately allocated as follows: 41% in equity securities, 35% in fixed income securities, 6% in absolute return strategies, 10% in real estate and 8% in cash and short-term securities. A decline in the value of plan assets could result in additional funding requirements. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made a $143 million contribution to its qualified pension plan. See Note 3, Pension and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2015, FirstEnergy's pension plan and OPEB assets incurred losses of $(172) million, or (2.7)%, as compared to an expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG's and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2015, approximately 68% of the funds were invested in fixed income securities, 25% of the funds were invested in equity securities and 7% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,552 million, $576 million and $147 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2015, excluding $7 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $58 million reduction in fair value as of December 31, 2015. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT funds or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2015, FirstEnergy contributed approximately $15 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2016	2017	2018	2019	2020	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 5	$ 2	$ —	$ —	$ —	$ 1,794	$ 1,801	$ 1,802
Average interest rate	8.9%	8.9%	—%	—%	—%	3.6%	3.6%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 660	$ 1,517	$ 1,330	$ 1,035	$ 541	$ 13,867	$ 18,950	$ 20,225
Average interest rate	5.5%	6.1%	4.8%	6.5%	5.5%	5.2%	5.3%	
Variable rate	$ —	$ 2	$ 6	$ 1,000	$ 200	$ 86	$ 1,294	$ 1,294
Average interest rate	—%	3.5%	—%	2.2%	1.9%	—%	2.0%	

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specific collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of offset. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. The majority of FirstEnergy's energy contract counterparties maintain investment-grade credit ratings.

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;
- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015.The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015 and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, NG, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*	*(MW)*	*($/MWD)*
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.

**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield's Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2015 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 14, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underlying the amounts included in the financial statements. Additional information regarding the application of accounting policies is included in the Combined Notes to Consolidated Financial Statements.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class. See Note 1, Organization and Basis of Presentation for additional details.

Regulatory Accounting

FirstEnergy's regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 14, Regulatory Matters for additional information.

FirstEnergy reviews the probability of recovery of regulatory assets at each balance sheet date and whenever new events occur. Similarly, FirstEnergy records regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Factors that may affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. If recovery of a regulatory asset is no longer probable, FirstEnergy will write off that regulatory asset as a charge against earnings.

Pension and OPEB Accounting

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels.

FirstEnergy provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2015 was $4.0 billion.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pension were 4.50%, 4.25% and 5.00% as of December 31, 2015, 2014 and 2013, respectively. The assumed discount rates for OPEB were 4.25%, 4.00% and 4.75% as of December 31, 2015, 2014 and 2013, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of $(172) million or (2.7)% compared to $387 million, or 6.2% in 2014 and losses of $(22) million, or (0.3)% in 2013 and assumed a 7.75% rate of return for both years on plan assets which generated $476 million, $496 million and $535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement. The expected return on plan assets for 2016 was lowered to 7.50%.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of $49 million and $1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Based on discount rates of 4.50% for pension, 4.25% for OPEB and an estimated return on assets of 7.50%, FirstEnergy expects its 2016 pre-tax net periodic benefit cost (including amounts capitalized) to be approximately $122 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2016). The following table reflects the portion of pension and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2015.

Postemployment Benefits Expense (Credits)	**2015**	**2014**	**2013**
		(In millions)	
Pension	$ 316	$ 939	$ (134)
OPEB	(61)	(101)	(196)
Total	$ 255	$ 838	$ (330)

Health care cost trends continue to increase and will affect future OPEB costs. The 2015 composite health care trend rate assumptions were approximately 6.0-5.5%, compared to 7.5-7.0% in 2014, gradually decreasing to 4.5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effects on 2016 pension and OPEB net periodic benefit costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by .25%	273	19	$ 292
Long-term return on assets	Decrease by .25%	13	1	$ 14
Health care trend rate	Increase by 1.0%	N/A	25	$ 25

Please see Note 3, Pension and Other Postemployment Benefits for additional information.

Long-Lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value. See Note 1, Organization and Basis of Presentation.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, Asset Retirement Obligations.

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. See Note 5, Taxes for additional information.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50%) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value or bypasses the qualitative assessment, then the two-step quantitative goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair values of these reporting units were, more likely than not, greater than their carrying values and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.
- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital, and revised environmental requirements could have a negative impact on future goodwill assessments.

See Note 1, Organization and Basis of Presentation for additional details.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information relating to market risk is set forth in Management's Discussion and Analysis of Financial Condition and Results of Operations.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2015 consolidated financial statements as stated in their audit report included herein.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held eight meetings in 2015.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework published in 2013, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2015. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Corp. 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 Item15(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 *Internal Control - Integrated Framework (2013)* 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 1 to the consolidated financial statements, in 2015 the Company changed the manner in which deferred tax assets and liabilities, along with any related valuation allowance, are classified on the balance sheet.

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

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2016

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions)	For the Years Ended December 31, 2015	2014	2013
REVENUES:			
Electric utilities	$ 10,636	$ 9,871	$ 9,451
Unregulated businesses	4,390	5,178	5,441
Total revenues*	15,026	15,049	14,892
OPERATING EXPENSES:			
Fuel	1,855	2,280	2,496
Purchased power	4,318	4,716	3,963
Other operating expenses	3,749	3,962	3,593
Pension and OPEB mark-to-market adjustment	242	835	(256)
Provision for depreciation	1,282	1,220	1,202
Amortization of regulatory assets, net	268	12	539
General taxes	978	962	978
Impairment of long-lived assets	42	—	795
Total operating expenses	12,734	13,987	13,310
OPERATING INCOME	2,292	1,062	1,582
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	—	(8)	(132)
Investment income (loss)	(22)	72	33
Impairment of equity method investment	(362)	—	—
Interest expense	(1,132)	(1,073)	(1,016)
Capitalized financing costs	117	118	103
Total other expense	(1,399)	(891)	(1,012)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	893	171	570
INCOME TAXES (BENEFITS)	315	(42)	195
INCOME FROM CONTINUING OPERATIONS	578	213	375
Discontinued operations (net of income taxes of $0, $69 and $9, respectively) (Note 19)	—	86	17
NET INCOME	$ 578	$ 299	$ 392
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Basic - Discontinued Operations (Note 19)	—	0.20	0.04
Basic - Net Income	$ 1.37	$ 0.71	$ 0.94
Diluted - Continuing Operations	$ 1.37	$ 0.51	$ 0.90
Diluted - Discontinued Operations (Note 19)	—	0.20	0.04
Diluted - Net Income	$ 1.37	$ 0.71	$ 0.94
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	422	420	418
Diluted	424	421	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.44	$ 1.44	$ 1.65

* Includes excise tax collections of $416 million, $420 million and $458 million in 2015, 2014 and 2013, respectively.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2015	2014	2013
NET INCOME	$ 578	$ 299	$ 392
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and OPEB prior service costs	(116)	(76)	(160)
Amortized gains (losses) on derivative hedges	5	(2)	3
Change in unrealized gain on available-for-sale securities	(11)	26	(10)
Other comprehensive loss	(122)	(52)	(167)
Income tax benefits on other comprehensive loss	(47)	(14)	(66)
Other comprehensive loss, net of tax	(75)	(38)	(101)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 503	$ 261	$ 291

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)		December 31, 2015		December 31, 2014
ASSETS				
CURRENT ASSETS:				
Cash and cash equivalents	$	131	$	85
Receivables-				
Customers, net of allowance for uncollectible accounts of $69 in 2015 and $59 in 2014		1,415		1,554
Other, net of allowance for uncollectible accounts of $5 in 2015 and 2014		180		225
Materials and supplies, at average cost		785		817
Prepaid taxes		135		128
Derivatives		157		159
Collateral		70		230
Other		167		160
		3,040		3,358
PROPERTY, PLANT AND EQUIPMENT:				
In service		49,952		47,484
Less — Accumulated provision for depreciation		15,160		14,150
		34,792		33,334
Construction work in progress		2,422		2,449
		37,214		35,783
INVESTMENTS:				
Nuclear plant decommissioning trusts		2,282		2,341
Other		506		881
		2,788		3,222
DEFERRED CHARGES AND OTHER ASSETS:				
Goodwill		6,418		6,418
Regulatory assets		1,348		1,411
Other		1,379		1,456
		9,145		9,285
	$	52,187	$	51,648
LIABILITIES AND CAPITALIZATION				
CURRENT LIABILITIES:				
Currently payable long-term debt	$	1,166	$	804
Short-term borrowings		1,708		1,799
Accounts payable		1,075		1,279
Accrued taxes		519		490
Accrued compensation and benefits		334		329
Derivatives		106		167
Other		694		693
		5,602		5,561
CAPITALIZATION:				
Common stockholders' equity-				
Common stock, $0.10 par value, authorized 490,000,000 shares - 423,560,397 and 421,102,570 shares outstanding as of December 31, 2015 and December 31, 2014, respectively		42		42
Other paid-in capital		9,952		9,847
Accumulated other comprehensive income		171		246
Retained earnings		2,256		2,285
Total common stockholders' equity		12,421		12,420
Noncontrolling interest		1		2
Total equity		12,422		12,422
Long-term debt and other long-term obligations		19,192		19,176
		31,614		31,598
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		6,773		6,539
Retirement benefits		4,245		3,932
Asset retirement obligations		1,410		1,387
Deferred gain on sale and leaseback transaction		791		824
Adverse power contract liability		197		217
Other		1,555		1,590
		14,971		14,489
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 15)				
	$	52,187	$	51,648

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock				
(In millions, except share amounts)	**Number of Shares**	**Par Value**	**Other Paid-In Capital**	**Accumulated Other Comprehensive Income**	**Retained Earnings**
	418,216,437	$ 42	$ 9,769	$ 385	$ 2,888
Net income					392
Amortized losses on derivative hedges, net of $1 million of income taxes				2	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(6)	
Pension and OPEB, net of $63 million of income tax benefits (Note 3)				(97)	
Stock-based compensation			(4)		
Cash dividends declared on common stock					(690)
Stock issuance - employee benefits	412,122		11		
Balance, December 31, 2013	418,628,559	42	9,776	284	2,590
Net income					299
Amortized gains on derivative hedges, net of $1 million of income tax benefits				(1)	
Change in unrealized gain on investments, net of $10 million of income taxes				16	
Pension and OPEB, net of $23 million of income tax benefits (Note 3)				(53)	
Stock-based compensation			20		
Cash dividends declared on common stock					(604)
Stock issuance - employee benefits	2,474,011		51		
Balance, December 31, 2014	421,102,570	42	9,847	246	2,285
Net income					578
Amortized gains on derivative hedges, net of $1 million of income taxes				4	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(7)	
Pension and OPEB, net of $44 million of income tax benefits (Note 3)				(72)	
Stock-based compensation			45		
Cash dividends declared on common stock					(607)
Stock issuance - employee benefits	2,457,827		60		
Balance, December 31, 2015	423,560,397	$ 42	$ 9,952	$ 171	$ 2,256

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 578	$ 299	$ 392
Adjustments to reconcile net income to net cash from operating activities-			
Depreciation and amortization, including nuclear fuel, regulatory assets, net, and customer intangible amortization	1,836	1,563	2,022
Impairments of long-lived assets	42	—	795
Investment impairment, including equity method investment	464	37	90
Pension and OPEB mark-to-market adjustment	242	835	(256)
Deferred income taxes and investment tax credits, net	284	162	243
Deferred costs on sale leaseback transaction, net	48	48	48
Deferred purchased power and other costs	(105)	(115)	(76)
Asset removal costs charged to income	55	28	20
Retirement benefits	(20)	(53)	(168)
Commodity derivative transactions, net (Note 10)	(73)	64	(3)
Pension trust contributions	(143)	—	—
Gain on sale of investment securities held in trusts	(23)	(64)	(56)
Loss on debt redemptions	—	8	132
Make-whole premiums paid on debt redemptions	—	—	(187)
Lease payments on sale and leaseback transaction	(131)	(137)	(136)
Income from discontinued operations (Note 19)	—	(86)	(17)
Changes in current assets and liabilities-			
Receivables	184	139	(114)
Materials and supplies	(15)	(65)	96
Prepayments and other current assets	(10)	126	(126)
Accounts payable	(243)	42	(25)
Accrued taxes	29	(165)	85
Accrued interest	(6)	31	(10)
Accrued compensation and benefits	5	(22)	19
Other current liabilities	75	23	(62)
Cash collateral, net	140	(54)	(36)
Other	234	69	(8)
Net cash provided from operating activities	3,447	2,713	2,662
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,311	4,528	3,745
Short-term borrowings, net	—	—	1,435
Redemptions and Repayments-			
Long-term debt	(879)	(1,759)	(3,600)
Short-term borrowings, net	(91)	(1,605)	—
Tender premiums paid on debt redemptions	—	—	(110)
Common stock dividend payments	(607)	(604)	(920)
Other	(13)	(47)	(73)
Net cash (used for) provided from financing activities	(279)	513	477
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,704)	(3,312)	(2,638)
Nuclear fuel	(190)	(233)	(250)
Proceeds from asset sales	20	394	4
Sales of investment securities held in trusts	1,534	2,133	2,047
Purchases of investment securities held in trusts	(1,648)	(2,236)	(2,096)
Cash investments	7	35	(23)
Asset removal costs	(142)	(153)	(146)
Other	1	13	9
Net cash used for investing activities	(3,122)	(3,359)	(3,093)
Net change in cash and cash equivalents	46	(133)	46
Cash and cash equivalents at beginning of period	85	218	172
Cash and cash equivalents at end of period	$ 131	$ 85	$ 218
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 1,028	$ 931	$ 969
Income taxes (received), net of refunds	$ 37	$ (103)	$ 36

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FE's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy and its subsidiaries are involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 miles of lines and two regional transmission operation centers.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not necessarily indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation as appropriate. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 8, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, AGC, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.

FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets as of December 31, 2015 and December 31, 2014, and the changes during the year ended December 31, 2015:

Regulatory Assets by Source	December 31, 2015	December 31, 2014	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 185	$ 240	$ (55)
Customer receivables for future income taxes	355	370	(15)
Nuclear decommissioning and spent fuel disposal costs	(272)	(305)	33
Asset removal costs	(372)	(254)	(118)
Deferred transmission costs	115	90	25
Deferred generation costs	243	281	(38)
Deferred distribution costs	335	182	153
Contract valuations	186	153	33
Storm-related costs	403	465	(62)
Other	170	189	(19)
Net Regulatory Assets included on the Consolidated Balance Sheets	$ 1,348	$ 1,411	$ (63)

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of December 31, 2015 and 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant-in-service to regulatory assets, which is being recovered over five years.

As of December 31, 2015 and December 31, 2014, FirstEnergy had approximately $116 million and $243 million of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within other noncurrent liabilities on the Consolidated Balance Sheets.

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements, and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, FirstEnergy accrues the estimated unbilled amount as revenue and reverses the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2015 and 2014 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2015 and 2014 are included below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2015		
Billed	$ 836	$ 165
Unbilled	579	110
Total	$ 1,415	$ 275
December 31, 2014		
Billed	$ 914	$ 239
Unbilled	640	176
Total	$ 1,554	$ 415

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2015	2014	2013
	(In millions, except per share amounts)		
Income from continuing operations available to common shareholders	$ 578	$ 213	$ 375
Discontinued operations (Note 19)	—	86	17
Net income	$ 578	$ 299	$ 392
Weighted average number of basic shares outstanding	422	420	418
Assumed exercise of dilutive stock options and awards[1]	2	1	1
Weighted average number of diluted shares outstanding	424	421	419
Earnings per share:			
Basic earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per basic share	$ 1.37	$ 0.71	$ 0.94
Diluted earnings per share:			
Continuing operations	$ 1.37	$ 0.51	$ 0.90
Discontinued operations (Note 19)	—	0.20	0.04
Earnings per diluted share	$ 1.37	$ 0.71	$ 0.94

(1) For the years ended December 31, 2015, 2014 and 2013, approximately one million, two million, and two million shares were excluded from the calculation of diluted shares outstanding, respectively, as their inclusion would be antidilutive.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within the CES segment's Property, plant and equipment and charged to fuel expense using the specific identification method. The cost of nuclear fuel included in CES' net plant as of December 31, 2015 was $418 million. Net plant in service balances by segment as of December 31, 2015 and 2014 were as follows:

Property, Plant and Equipment	December 31, 2015 In Service[(2)]	Accum. Depr.	Net Plant	December 31, 2014 In Service[(2)]	Accum. Depr.	Net Plant
			(In millions)			
Regulated Distribution	$ 24,553	$ (7,058)	$ 17,495	$ 23,973	$ (6,759)	$ 17,214
Regulated Transmission	7,703	(1,647)	6,056	6,634	(1,595)	5,039
Competitive Energy Services[(1)]	17,214	(6,213)	11,001	16,442	(5,598)	10,844
Corporate/Other	482	(242)	240	435	(198)	237
Total	$ 49,952	$ (15,160)	$ 34,792	$ 47,484	$ (14,150)	$ 33,334

[(1)] Primarily consists of generating assets and nuclear fuel as discussed above.
[(2)] Includes capital leases of $253 million and $281 million at December 31, 2015 and 2014, respectively.

The major classes of Property, plant and equipment are largely consistent with the segment disclosures above, with the exception of Regulated Distribution, which has approximately $2.0 billion of regulated generation net plant in service.

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's and FES' electric plant in 2015, 2014 and 2013 are shown in the following table:

	Annual Composite Depreciation Rate 2015	2014	2013
FirstEnergy	2.5%	2.5%	2.6%
FES	3.2%	3.1%	3.1%

For the years ended December 31, 2015, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $49 million, $49 million and $28 million, respectively, of allowance for equity funds used during construction and $68 million, $69 million and $75 million, respectively, of capitalized interest.

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,003 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, plant and equipment includes $666 million representing AGC's share in this facility as of December 31, 2015 of which $484 million is unregulated and included within the CES segment. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statements of Income.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset.

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not the timing of the liability recognition.

AROs as of December 31, 2015, are described further in Note 13, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value.

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. In connection with the transaction, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The impairment charge recognized in 2013 is included within the results of the Regulated Distribution segment.

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the Hatfield's Ferry, generating Units 1-3, and Mitchell, generating units 2-3. As a result of this decision FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge recognized in 2013 is included within the results of the CES segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

During 2015, FirstEnergy recognized impairments totaling $42 million associated with certain non-core assets, including equipment and facilities. The impairment charges are included within the Regulated Distribution segment ($8 million) and the CES segment ($34 million).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents goodwill by reporting unit:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
	(In millions)			
Balance as of December 31, 2015	$ 5,092	$ 526	$ 800	$ 6,418

There were no changes in goodwill for any reporting unit during 2015. As of December 31, 2015 and 2014, total goodwill recognized by FES was $23 million. Neither FirstEnergy nor FES has accumulated impairment charges as of December 31, 2015.

Annual impairment testing is conducted as of July 31 of each year and for 2015, 2014 and 2013, the analysis indicated no impairment of goodwill. For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- **Future Energy and Capacity Prices:** FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- **Retail Sales and Margin:** FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.

- **Operating and Capital Costs:** FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.
- **Discount Rate:** A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- **Terminal Value:** A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital and revised environmental requirements could have a negative impact on future goodwill assessments.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets. In 2015, 2014 and 2013, FirstEnergy recognized $102 million, $37 million and $90 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $90 million, $33 million and $79 million, respectively. The fair values of FirstEnergy's investments are disclosed in Note 9, Fair Value Measurements.

FirstEnergy holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. In 2015, Global Holding incurred losses primarily as a result of declines in coal prices due to weakening global and U.S. coal demand. Based on the significant decline in coal pricing and the current outlook for the coal market, including the significant decline in the market capitalization of coal companies in 2015, FirstEnergy assessed the value of its investment in Global Holding and determined there was a decline in the fair value of the investment below its carrying value that was other than temporary, resulting in an a pre-tax impairment charge of $362 million. Key assumptions incorporated into the discounted cash flow analysis utilized in the impairment analysis included the discount rate, future long term coal prices, production levels, sales forecasts, projected capital and operating costs. The impairment charge is classified as a component of Other Income (Expense) in the Consolidated Statement of Income. See Note 8, Variable Interest Entities, for further discussion of FirstEnergy's investment in Global Holding.

INVENTORY

Materials and supplies inventory includes fuel inventory and the distribution, transmission and generation plant materials, net of reserve for excess and obsolete inventory. Materials are generally charged to inventory at weighted average cost when purchased and expensed or capitalized, as appropriate, when used or installed. Fuel inventory is accounted for at weighted average cost when purchased, and recorded to fuel expense when consumed.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2015, the FASB issued, ASU 2015-02 "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In April 2015, the FASB issued, ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which states given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to the line-of-credit arrangements, the SEC staff would not object to presenting those deferred debt issuance costs as an asset and subsequently amortizing the costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy will adopt ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES debt issuance costs included in Deferred Charges and Other Assets were $93 million and $17 million, respectively. FirstEnergy will elect to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In August 2015, the FASB issued ASU 2015 -13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. There was no material effect on FirstEnergy's financial statements resulting from the issuance of ASU 2015-13.

In November 2015, the FASB issued ASU 2015 - 17, "Balance Sheet Classification of Deferred Taxes", which requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new guidance will be effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption is permitted for all entities as of the beginning of an interim or annual reporting period. The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. FirstEnergy early adopted ASU 2015-17 as of December 2015, and applied the new guidance retrospectively to all prior periods presented in the financial statements. There was no impact from the early adoption of ASU 2015-17 on the Consolidated Statements of Income. On the Consolidated Balance Sheet as of December 31, 2014, FirstEnergy and FES reclassified $518 million and $27 million of Accumulated Deferred Income Taxes from Current Assets to Noncurrent Liabilities.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities". Changes to the current GAAP model primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FirstEnergy are shown in the following table:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ (38)	$ 15	$ 408	$ 385
Other comprehensive income before reclassifications	—	46	35	81
Amounts reclassified from AOCI	3	(56)	(195)	(248)
Other comprehensive income (loss)	3	(10)	(160)	(167)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(63)	(66)
Other comprehensive income (loss), net of tax	2	(6)	(97)	(101)
AOCI Balance, December 31, 2013	$ (36)	$ 9	$ 311	$ 284
Other comprehensive income before reclassifications	—	89	92	181
Amounts reclassified from AOCI	(2)	(63)	(168)	(233)
Other comprehensive income (loss)	(2)	26	(76)	(52)
Income tax (benefits) on other comprehensive income (loss)	(1)	10	(23)	(14)
Other comprehensive income (loss), net of tax	(1)	16	(53)	(38)
AOCI Balance, December 31, 2014	$ (37)	$ 25	$ 258	$ 246
Other comprehensive income before reclassifications	—	14	10	24
Amounts reclassified from AOCI	5	(25)	(126)	(146)
Other comprehensive income (loss)	5	(11)	(116)	(122)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(44)	(47)
Other comprehensive income (loss), net of tax	4	(7)	(72)	(75)
AOCI Balance, December 31, 2015	$ (33)	$ 18	$ 186	$ 171

The following amounts were reclassified from AOCI for FirstEnergy in the years ended December 31, 2015, 2014 and 2013:

FirstEnergy

Reclassifications from AOCI [2]	**Year Ended December 31,**			**Affected Line Item in Consolidated Statements of Income**
	2015	**2014**	**2013**	
		(In millions)		
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	8	8	11	Interest expense
	5	(2)	3	Total before taxes
	(1)	1	(1)	Income taxes (benefits)
	$ 4	$ (1)	$ 2	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (25)	$ (63)	$ (56)	Investment income (loss)
	9	24	21	Income taxes (benefits)
	$ (16)	$ (39)	$ (35)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (126)	$ (168)	$ (195)	[1]
	49	65	75	Income taxes (benefits)
	$ (77)	$ (103)	$ (120)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

The changes in AOCI for the years ended December 31, 2015, 2014 and 2013 for FES are shown in the following table:

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2013	$ 3	$ 13	$ 56	$ 72
Other comprehensive income before reclassifications	—	41	5	46
Amounts reclassified from AOCI	(6)	(49)	(20)	(75)
Other comprehensive loss	(6)	(8)	(15)	(29)
Income tax benefits on other comprehensive loss	(2)	(3)	(6)	(11)
Other comprehensive loss, net of tax	(4)	(5)	(9)	(18)
AOCI Balance, December 31, 2013	$ (1)	$ 8	$ 47	$ 54
Other comprehensive income before reclassifications	—	80	13	93
Amounts reclassified from AOCI	(10)	(59)	(19)	(88)
Other comprehensive income (loss)	(10)	21	(6)	5
Income tax (benefits) on other comprehensive income (loss)	(4)	8	(2)	2
Other comprehensive income (loss), net of tax	(6)	13	(4)	3
AOCI Balance, December 31, 2014	$ (7)	$ 21	$ 43	$ 57
Other comprehensive income before reclassifications	—	15	10	25
Amounts reclassified from AOCI	(3)	(24)	(16)	(43)
Other comprehensive loss	(3)	(9)	(6)	(18)
Income tax benefits on other comprehensive loss	(1)	(4)	(2)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(4)	(11)
AOCI Balance, December 31, 2015	$ (9)	$ 16	$ 39	$ 46

The following amounts were reclassified from AOCI for FES in the years ended December 31, 2015, 2014 and 2013:

FES

Reclassifications from AOCI [2]	**Year Ended December 31,** 2015	2014	2013	**Affected Line Item in Consolidated Statements of Income**
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (3)	$ (10)	$ (8)	Other operating expenses
Long-term debt	—	—	2	Interest expense - other
	(3)	(10)	(6)	Total before taxes
	1	4	2	Income taxes (benefits)
	$ (2)	$ (6)	$ (4)	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (24)	$ (59)	$ (49)	Investment income (loss)
	9	22	18	Income taxes (benefits)
	$ (15)	$ (37)	$ (31)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (16)	$ (19)	$ (20)	[1]
	6	7	8	Income taxes (benefits)
	$ (10)	$ (12)	$ (12)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pension and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. In 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Payment of benefits for participants that elected an immediate lump sum cash payment or an annuity resulted in a $40 million reduction to the underfunded status of the pension plan. Additionally, during 2015 and 2014, certain unions ratified their labor agreements that ended subsidized retiree health care resulting in a reduction to the OPEB benefit obligation by approximately $10 million and $97 million, respectively.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and OPEB expense, primarily service costs, interest on obligations, assumed return on assets and prior service costs, are recorded on a monthly basis. The pension and OPEB mark-to-market adjustment for the years ended December 31, 2015, 2014, and 2013 were $369 million ($242 million net of amounts capitalized), $1,243 million ($835 million net of amounts capitalized), and $(396) million ($(256) million net of amounts capitalized), respectively. In 2015, the pension and OPEB mark-to-market adjustment primarily reflects lower than expected asset returns as well as the impact of other demographic assumptions, including revisions to mortality assumptions, partially offset by a 25 basis point increase in the discount rate.

FirstEnergy's pension and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2015, FirstEnergy made contributions of $143 million to its qualified pension plan. In 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $160 million has been contributed to date. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 with cash, equity or a combination thereof, depending on, among other things, market conditions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2015, FirstEnergy's qualified pension and OPEB plan assets experienced losses of \$(172) million, or (2.7)% compared to earnings of \$387 million, or 6.2% in 2014 and losses of \$(22) million, or (0.3)% in 2013, and assumed a 7.75% rate of return for each year on plan assets which generated \$476 million, \$496 million and \$535 million of expected returns on plan assets, respectively. The expected return on pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

During 2014, the Society of Actuaries published new mortality tables and improvement scales reflecting improved life expectancies and an expectation that the trend will continue. An analysis of FirstEnergy pension and OPEB plan mortality data indicated the use of the RP2014 mortality table with blue collar adjustment for females and projection scale SS2014INT was most appropriate as of December 31, 2015. As such, the RP2014 mortality table with projection scale SS2014INT was utilized to determine the 2015 benefit cost and obligation as of December 31, 2015 for the FirstEnergy pension and OPEB plans. The impact of using the RP2014 mortality table and projection scale SS2014INT resulted in an increase in the projected benefit obligation of \$49 million and \$1 million for the pension and OPEB plans, respectively, and was included in the 2015 pension and OPEB mark-to-market adjustment.

Obligations and Funded Status	Pension 2015	Pension 2014	OPEB 2015	OPEB 2014
		(In millions)		
Change in benefit obligation:				
Benefit obligation as of January 1	$ 9,249	$ 8,263	$ 757	$ 879
Service cost	193	167	5	9
Interest cost	383	402	29	39
Plan participants' contributions	—	—	6	16
Plan amendments	—	5	(10)	(97)
Medicare retiree drug subsidy	—	—	1	—
Actuarial (gain) loss	(277)	1,123	(2)	13
Benefits paid	(469)	(711)	(62)	(102)
Benefit obligation as of December 31	$ 9,079	$ 9,249	$ 724	$ 757
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 5,824	$ 6,171	$ 464	$ 495
Actual return (losses) on plan assets	(178)	349	6	38
Company contributions	161	15	17	17
Plan participants' contributions	—	—	6	16
Benefits paid	(469)	(711)	(62)	(102)
Fair value of plan assets as of December 31	$ 5,338	$ 5,824	$ 431	$ 464
Funded Status:				
Qualified plan	$ (3,366)	$ (3,064)		
Non-qualified plans	(375)	(361)		
Funded Status	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Accumulated benefit obligation	$ 8,579	$ 8,744	$ —	$ —
Amounts Recognized on the Balance Sheet:				
Current liabilities	$ (18)	$ (17)	$ —	$ —
Noncurrent liabilities	(3,723)	(3,408)	(293)	(293)
Net liability as of December 31	$ (3,741)	$ (3,425)	$ (293)	$ (293)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 37	$ 45	$ (355)	$ (479)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	4.50%	4.25%	4.25%	4.00%
Rate of compensation increase	4.20%	4.20%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	6.0-5.5%	7.5-7.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2026	2026
Allocation of Plan Assets (as of December 31)				
Equity securities	40%	36%	51%	49%
Bonds	34%	33%	43%	40%
Absolute return strategies	7%	14%	—%	1%
Real estate	11%	7%	—%	1%
Derivatives	—%	1%	—%	—%
Cash and short-term securities	8%	9%	6%	9%
Total	100%	100%	100%	100%

The estimated 2016 amortization of pension and OPEB prior service costs (credits) from AOCI into net periodic pension and OPEB costs (credits) is approximately $8 million and $(80) million, respectively.

Components of Net Periodic Benefit Costs	Pension 2015	Pension 2014	Pension 2013	OPEB 2015	OPEB 2014	OPEB 2013
			(In millions)			
Service cost	$ 193	$ 167	$ 197	$ 5	$ 9	$ 13
Interest cost	383	402	372	29	39	37
Expected return on plan assets	(443)	(462)	(501)	(33)	(34)	(34)
Amortization of prior service cost (credit)	8	8	12	(134)	(176)	(207)
Pension & OPEB mark-to-market adjustment	344	1,235	(267)	25	8	(129)
Net periodic cost (credit)	$ 485	$ 1,350	$ (187)	$ (108)	$ (154)	$ (320)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension 2015	Pension 2014	Pension 2013	OPEB 2015	OPEB 2014	OPEB 2013
Weighted-average discount rate	4.25%	5.00%	4.25%	4.00%	4.75%	4.00%
Expected long-term return on plan assets	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
Rate of compensation increase	4.20%	4.20%	4.70%	N/A	N/A	N/A

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed rates of return on plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy. In 2016, FirstEnergy decreased the expected long-term return on plan assets to 7.50%.

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 9, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2015 and 2014.

	December 31, 2015 Level 1	Level 2	Level 3	Total	Asset Allocation
		(In millions)			
Cash and short-term securities	$ —	$ 427	$ —	$ 427	8%
Equity investments					
Domestic	869	75	—	944	18%
International	395	794	—	1,189	22%
Fixed income					
Government bonds	—	232	—	232	4%
Corporate bonds	—	1,115	—	1,115	21%
High yield debt	—	438	—	438	8%
Mortgage-backed securities (non-government)	—	31	—	31	1%
Alternatives					
Hedge funds (Absolute return)	—	343	—	343	7%
Derivatives	—	15	—	15	—%
Private equity funds	—	—	24	24	—%
Real estate funds	—	—	587	587	11%
Total [(1)]	$ 1,264	$ 3,470	$ 611	$ 5,345	100%

(1) Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 517	$ —	$ 517	9%
Equity investments					
Domestic	1,266	8	—	1,274	22%
International	355	414	—	769	14%
Fixed income					
Government bonds	—	159	—	159	3%
Corporate bonds	—	1,386	—	1,386	24%
High yield debt	—	300	—	300	5%
Mortgage-backed securities (non-government)	—	37	—	37	1%
Alternatives					
Hedge funds (Absolute return)	—	809	—	809	14%
Derivatives	—	35	—	35	1%
Private equity funds	—	—	25	25	—%
Real estate funds	—	—	421	421	7%
Total [(1)]	$ 1,621	$ 3,665	$ 446	$ 5,732	100%

(1) Excludes $92 million as of December 31, 2014 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2015 and 2014:

	Private Equity Funds	Real Estate Funds
	(In millions)	
Balance as of January 1, 2014	$ 27	$ 385
Actual return on plan assets:		
Unrealized gains (losses)	(2)	17
Realized gains	1	14
Transfers in (out)	(1)	5
Balance as of December 31, 2014	$ 25	$ 421
Actual return on plan assets:		
Unrealized gains	—	42
Realized gains (losses)	(1)	16
Transfers in	—	108
Balance as of December 31, 2015	$ 24	$ 587

As of December 31, 2015 and 2014, the OPEB trust investments measured at fair value were as follows:

	December 31, 2015				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$ —	$ 25	$ —	$ 25	6%
Equity investment					
Domestic	219	—	—	219	50%
International	1	3	—	4	1%
Fixed income					
U.S. treasuries	—	42	—	42	10%
Government bonds	—	114	—	114	26%
Corporate bonds	—	27	—	27	6%
High yield debt	—	1	—	1	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	1	—	1	—%
Real estate funds	—	—	2	2	—%
Total [(1)]	$ 220	$ 216	$ 2	$ 438	100%

(1) Excludes $(7) million as of December 31, 2015 of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

	December 31, 2014				
	Level 1	Level 2	Level 3	Total	Asset Allocation
	(In millions)				
Cash and short-term securities	$ —	$ 41	$ —	$ 41	9%
Equity investment					
Domestic	230	—	—	230	48%
International	3	3	—	6	1%
Fixed income					
U.S. treasuries	—	41	—	41	9%
Government bonds	—	110	—	110	23%
Corporate bonds	—	32	—	32	7%
High yield debt	—	2	—	2	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	5	—	5	1%
Real estate funds	—	—	3	3	1%
Total [(1)]	$ 233	$ 237	$ 3	$ 473	100%

(1) Excludes $(9) million as of December 31, 2014, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2015 and 2014:

	Real Estate Funds
Balance as of January 1, 2014	$ 5
Transfers out	(2)
Balance as of December 31, 2014	$ 3
Transfers out	(1)
Balance as of December 31, 2015	$ 2

FirstEnergy follows a total return investment approach using a mix of equities, fixed income and other available investments while taking into account the pension plan liabilities to optimize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

FirstEnergy's target asset allocations for its pension and OPEB trust portfolios for 2015 and 2014 are shown in the following table:

Target Asset Allocations		
	2015	2014
Equities	38%	42%
Fixed income	30%	32%
Absolute return strategies	8%	14%
Real estate	10%	5%
Alternative investments	8%	1%
Cash	6%	6%
	100%	100%

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

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 1	$ (1)
Effect on accumulated benefit obligation	$ 26	$ (23)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets and other payments, net of participant contributions:

		OPEB	
	Pension	Benefit Payments	Subsidy Receipts
		(In millions)	
2016	$ 484	$ 54	$ (3)
2017	505	54	(3)
2018	522	54	(3)
2019	533	54	(3)
2020	551	54	(3)
Years 2021-2025	2,946	259	(9)

FES' share of the pension and OPEB net (liability) asset as of December 31, 2015 and 2014, was as follows:

	Pension		OPEB	
	2015	2014	2015	2014
	(In millions)			
Net (Liability) Asset	$ (303)	$ (295)	$ 25	$ 10

FES' share of the net periodic benefit cost (credit), including the pension and OPEB mark-to-market adjustment, for the three years ended December 31, 2015 was as follows:

	Pension			OPEB		
	2015	2014	2013	2015	2014	2013
	(In millions)					
Net Periodic Cost (Credit)	$ 10	$ 150	$ (30)	$ (22)	$ (24)	$ (40)

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy grants stock-based awards through the ICP 2015, primarily in the form of restricted stock and performance-based restricted stock units. Under FirstEnergy's previous incentive compensation plan, the ICP 2007, FirstEnergy also granted stock options and performance shares. The ICP 2007 and ICP 2015 include shareholder authorization to issue 29 million shares and 10 million shares, respectively, of common stock or their equivalent. As of December 31, 2015, approximately 9.9 million shares were available for future grants under the ICP 2015 assuming maximum performance metrics are achieved for the outstanding cycles of restricted stock units. No shares are available for future grants under the ICP 2007. Any shares not issued due to forfeitures or cancellations are added back to the ICP 2015. Shares used under the ICP 2007 and ICP 2015 are issued from authorized but unissued common stock. Vesting periods range from one to ten years, with the majority of awards having a vesting period of three years. FirstEnergy also issues stock through its 401(k) Savings Plan, EDCP, and DCPD. FirstEnergy records the compensation costs for stock-based compensation awards that will be paid in stock over the vesting period based on the fair value on the grant date, less estimated forfeitures. FirstEnergy adjusts the compensation costs for stock-based compensation awards that will be paid in cash based on changes in the fair value of the award as of each reporting date. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or settled. Realized tax benefits during the years ended December 31, 2015, 2014 and 2013 were $10 million, $13 million and $13 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as a financing activity on the Consolidated Statements of Cash Flows.

Stock-based compensation costs and the amount of stock-based compensation expense capitalized related to FirstEnergy and FES plans are included in the following tables:

FirstEnergy	Years ended December 31,		
Stock-based Compensation Plan	2015	2014	2013
	(In millions)		
Restricted Stock Units	$ 46	$ 26	$ 36
Restricted Stock	2	5	6
Performance Shares	—	5	(10)
401(k) Savings Plan	38	25	25
EDCP & DCPD	3	8	3
Total	$ 89	$ 69	$ 60
Stock-based compensation costs capitalized	$ 32	$ 23	$ 20

FES Stock-based Compensation Plan	Years ended December 31, 2015	2014	2013
		(In millions)	
Restricted Stock Units	$ 6	$ 4	$ 6
Performance Shares	—	1	(1)
401(k) Savings Plan	5	4	4
Total	$ 11	$ 9	$ 9
Stock-based compensation costs capitalized	$ 1	$ 1	$ 1

Stock option expense was not material for FirstEnergy or FES for the years December 31, 2015, 2014 or 2013. Income tax benefits associated with stock based compensation plan expense were $12 million, $14 million and $23 million (FES - $2 million, $2 million and $1 million) for the years ended 2015, 2014 and 2013, respectively.

Restricted Stock Units

Beginning with the performance-based restricted stock units granted in 2015, two-thirds will be paid in stock and one-third will be paid in cash. Prior to 2015, all performance-based restricted stock units were paid in stock. Restricted stock units paid in stock provide the participant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets. The grant date fair value of the stock portion of the restricted stock unit award is measured based on the average of the high and low prices of FE common stock on the date of grant. Compensation expense is recognized for the grant date fair value of awards that are expected to vest. Restricted stock units paid in cash provide the participant the right to receive cash based on the numbers of stock units set forth in the agreement and value of the equivalent number of shares of FE common stock as of the vesting date. The cash portion of the restricted stock unit award is considered a liability award, which is remeasured each period based on FE's stock price and projected performance adjustments. The liability recorded for cash performance based restricted stock units as of December 31, 2015 was $3 million. No cash was paid to settle the restricted stock unit obligations in 2015. The vesting period for each of the awards was three years. Dividend equivalents are received on the restricted stock units and are reinvested in additional restricted stock units and subject to the same performance conditions.

Restricted stock unit activity for the year ended December 31, 2015, was as follows:

Restricted Stock Unit Activity	Shares	Weighted-Average Grant Date Fair Value
Nonvested as of January 1, 2015	2,069,518	$ 37.65
Granted in 2015	1,157,755	35.27
Forfeited in 2015	(231,271)	34.19
Vested in 2015[(1)]	(559,114)	44.58
Nonvested as of December 31, 2015	2,436,888	$ 35.26

[(1)] Excludes dividend equivalents of 89,681 earned during vesting period

The weighted average fair value of awards granted in 2015, 2014 and 2013 were $35.27, $32.17 and $39.90 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock units vested was $22 million, $28 million, and $37 million, respectively. As of December 31, 2015, there was $32 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock units; that cost is expected to be recognized over a period of approximately two years.

Restricted Stock

Certain employees receive awards of FE restricted stock (as opposed to "units" with the right to receive shares at the end of the restriction period) subject to restrictions that lapse over a defined period of time or upon achieving performance results. The fair value of restricted stock is measured based on the average of the high and low prices of FirstEnergy common stock on the date of grant. Dividends are received on the restricted stock and are reinvested in additional shares of restricted stock.

Restricted common stock (restricted stock) activity for the year ended December 31, 2015, was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2015	342,286	$ 45.29
Granted in 2015	65,434	32.98
Forfeited in 2015	(26,079)	57.58
Vested in 2015[1]	(190,985)	43.17
Nonvested as of December 31, 2015	190,656	$ 40.65

[1] Excludes 52,872 shares for dividends earned during vesting period

The weighted average vesting period for restricted stock granted in 2015 was 5.59 years. The weighted average fair value of awards granted in 2015, 2014, and 2013 were $32.98, $32.71 and $42.53 respectively. For the years ended December 31, 2015, 2014, and 2013, the fair value of restricted stock vested was $8 million, $4 million, and $7 million, respectively. As of December 31, 2015, there was $3 million of total unrecognized compensation cost related to non-vested restricted stock, which is expected to be recognized over a period of approximately three years.

Stock Options

Stock options have been granted to certain employees allowing them to purchase a specified number of common shares at a fixed exercise price over a defined period of time. Stock options generally expire ten years from the date of grant. There were no stock options granted in 2015. Stock option activity during 2015 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2015 (1,077,988 options exercisable)	1,439,145	$ 44.83
Options exercised	(18,551)	29.53
Options forfeited	(8,623)	68.02
Balance, December 31, 2015 (1,211,358 options exercisable)	1,411,971	$ 44.89

Cash received from the exercise of stock options in 2015, 2014 and 2013 was $1 million, $1 million and $19 million, respectively. The total intrinsic value of options exercised during 2015 was not material. The weighted-average remaining contractual term of options outstanding as of December 31, 2015 was 3.58 years.

Performance Shares

Prior to the 2015 grant of performance-based restricted stock units discussed above, the Company granted performance shares. Performance shares are share equivalents and do not have voting rights. The performance shares outstanding track the performance of FE's common stock over a three-year vesting period. Dividend equivalents accrue on performance shares and are reinvested into additional performance shares with the same performance conditions. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. No performance shares were granted in 2015. In 2014, $3 million cash was paid to settle performance share obligations. During 2015 and 2013, no cash was paid to settle performance shares due to the performance criteria not being met for the previous three-year vesting period.

401(k) Savings Plan

In 2015 and 2014, 1,072,494 and 756,412 shares of FE common stock, respectively, were issued and contributed to participants' accounts. In 2013, approximately 708,000 shares of FE common stock were purchased on the market and contributed to participants' accounts.

EDCP

Under the EDCP, covered employees can defer a portion of their compensation, including base salary, annual incentive awards and/or long-term incentive awards, into unfunded accounts. Annual incentive and long-term incentive awards may be deferred in FE stock accounts. Base salary and annual incentive awards may be deferred into a retirement cash account which earns interest. Dividends are calculated quarterly on stock units outstanding and are credited in the form of additional stock units. The form of payout as stock or cash can vary depending upon the form of the award, the duration of the deferral and other factors. Certain types of deferrals such as dividend equivalent units, Short-Term Incentive Awards, and performance share awards are required to be paid in cash. Until 2015, payouts of the stock accounts typically occurred three years from the date of deferral, although participants could have elected to defer their shares into a retirement stock account that would pay out in cash upon retirement. In 2015, FirstEnergy amended the EDCP to eliminate the right to receive deferred shares after three years, effective for deferrals made on or after November 1, 2015. Awards deferred into a retirement stock account will pay out in cash upon separation from service, death or disability. Interest accrues on the cash allocated to the retirement cash account and the balance will pay out in cash over a time period as elected by the participant.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $9 million and $8 million as of December 31, 2015 and December 31, 2014, respectively, is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

5. TAXES

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

On December 18, 2015, the President signed into law the Protecting Americans from Tax Hikes Act of 2015 (the Act). The Act, among other things, made permanent the R&D tax credit, and also extended accelerated depreciation of qualified capital investments placed into service. This bonus depreciation provision is 50% for qualifying assets placed into service from 2015 through 2017, 40% for qualifying assets placed into service in 2018 and 30% for qualifying assets placed into service in 2019. FirstEnergy and FES recorded the effects of the Act that apply to 2015 in the fourth quarter of 2015. The extension of the tax benefits did not have a significant impact to the effective tax rate.

INCOME TAXES (BENEFITS)[1]	2015	2014	2013
		(In millions)	
FirstEnergy			
Currently payable (receivable)-			
Federal	$ 1	$ (132)	$ (118)
State	30	(72)	70
	31	(204)	(48)
Deferred, net-			
Federal	277	214	305
State	15	(42)	(54)
	292	172	251
Investment tax credit amortization	(8)	(10)	(8)
Total provision for income taxes (benefits)	$ 315	$ (42)	$ 195
FES			
Currently payable (receivable)-			
Federal	$ (56)	$ (222)	$ (300)
State	2	(13)	(3)
	(54)	(235)	(303)
Deferred, net-			
Federal	103	25	317
State	18	(14)	(4)
	121	11	313
Investment tax credit amortization	(2)	(4)	(4)
Total provision for income taxes (benefits)	$ 65	$ (228)	$ 6

[1]Provision for Income Taxes (Benefits) on Income from Continuing Operations. Currently payable (receivable) in 2014 excludes $106 million and $12 million of federal and state taxes, respectively, associated with discontinued operations. Deferred, net in 2014 excludes $44 million and $5 million of federal and state tax benefits, respectively, associated with discontinued operations.

FirstEnergy and FES tax rates are affected by permanent items, such as AFUDC equity and other flow-through items as well as discrete items that may occur in any given period, but are not consistent from period to period. The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total income taxes on continuing operations for the three years ended December 31:

	2015	2014	2013
		(In millions)	
FirstEnergy			
Income from Continuing Operations before income taxes	$ 893	$ 171	$ 570
Federal income tax expense at statutory rate (35%)	$ 313	$ 60	$ 199
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	34	12	10
AFUDC equity and other flow-through	(16)	(13)	(7)
Amortization of investment tax credits	(8)	(10)	(8)
Change in accounting method	(8)	(27)	—
ESOP dividend	(6)	(6)	(9)
Tax basis balance sheet adjustments	—	(25)	—
Uncertain tax positions	1	(35)	(2)
Other, net	5	2	12
Total income taxes (benefits)	$ 315	$ (42)	$ 195
Effective income tax rate	35.3%	(24.6)%	34.2%
FES			
Income (loss) from Continuing Operations before income taxes (benefits)	$ 147	$ (588)	$ 52
Federal income tax expense (benefit) at statutory rate (35%)	$ 51	$ (206)	$ 18
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal tax benefit	16	(14)	(5)
Amortization of investment tax credits	(2)	(4)	(4)
ESOP dividend	(1)	(1)	(2)
Uncertain tax positions	5	—	—
Other, net	(4)	(3)	(1)
Total income taxes (benefits)	$ 65	$ (228)	$ 6
Effective income tax rate	44.2%	38.8 %	11.5%

In 2015, FirstEnergy's effective tax rate was 35.3% compared to (24.6)% in 2014. The increase in the effective tax rate year-over-year resulted from lower tax benefits in 2015 as compared to 2014, primarily related to IRS approved changes in accounting methods, reduced tax benefits on uncertain tax positions, partially offset by lower valuation allowances required on state and municipal net operating loss carryforwards that FirstEnergy believes are no longer realizable. Additionally, during 2014, income tax benefits of $25 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the FirstEnergy's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period. The increase in the effective rate was also impacted by higher income from continuing operations.

In 2015, FES' effective tax rate on income from continuing operations was 44.2% compared to 38.8% on a loss from continuing operations in 2014. The increase in the effective tax rate is primarily due to an increase in reserves associated with uncertain tax positions in 2015 and the absence of tax benefits recognized in 2014 associated with changes in state apportionment factors, partially offset by lower valuation allowances recorded on state and municipal NOL carryforwards that FirstEnergy believes are no longer realizable.

Accumulated deferred income taxes as of December 31, 2015 and 2014 are as follows:

	2015	2014
	(In millions)	
FirstEnergy		
Property basis differences	$ 9,920	$ 9,354
Deferred sale and leaseback gain	(360)	(381)
Pension and OPEB	(1,541)	(1,433)
Nuclear decommissioning activities	480	458
Asset retirement obligations	(731)	(641)
Regulatory asset/liability	763	768
Loss carryforwards and AMT credits	(1,965)	(1,932)
Loss carryforward valuation reserve	192	174
All other	15	172
Net deferred income tax liability	$ 6,773	$ 6,539
FES		
Property basis differences	$ 1,901	$ 1,749
Deferred sale and leaseback gain	(342)	(356)
Pension and OPEB	(393)	(373)
Lease market valuation liability	95	75
Nuclear decommissioning activities	483	489
Asset retirement obligations	(509)	(486)
Loss carryforwards and AMT credits	(687)	(631)
Loss carryforward valuation reserve	46	32
All other	6	(15)
Net deferred income tax liability	$ 600	$ 484

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state taxing authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2011-2014. In January 2015, the IRS completed its examination of the 2013 federal income tax return and issued a Revenue Agent Report and there were no material impacts to FirstEnergy's effective tax rate associated with this examination. Tax year 2014 is currently under review by the IRS.

FirstEnergy has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2015, the deferred income tax assets, before any valuation allowances, for loss carryforwards and AMT credits consisted of $1.5 billion of Federal NOL carryforwards, net of tax, that will begin to expire in 2030, Federal AMT credits of $26 million, net of tax, that have an indefinite carryforward period, and $398 million, net of tax, of state and local NOL carryforwards that will begin to expire in 2016.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $10 billion for FirstEnergy, of which approximately $6 billion is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	FirstEnergy		FES	
	(In millions)			
	State	Local	State	Local
2016-2020	$ 403	$ 2,983	$ 95	$ 1,820
2021-2025	1,323	—	68	—
2026-2030	2,205	—	259	—
2031-2035	3,245	—	1,128	—
	$ 7,176	$ 2,983	$ 1,550	$ 1,820

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. A recognition threshold and measurement attribute is utilized for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2015 and 2014, FirstEnergy's total unrecognized income tax benefits were approximately $34 million. If ultimately recognized in future years, approximately $29 million of unrecognized income tax benefits as of December 31, 2015, would impact the effective tax rate. As of December 31, 2015, it is reasonably possible that approximately $9 million of unrecognized tax benefits may be resolved during 2016 as a result of the statute of limitations expiring, of which approximately $7 million would affect FirstEnergy's effective tax rate.

The following table summarizes the changes in unrecognized tax positions for the years ended 2015, 2014 and 2013:

	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2013	$ 43	$ 3
Prior years increases	10	—
Prior years decreases	(5)	—
Balance, December 31, 2013	$ 48	$ 3
Current year increases	4	—
Prior years increases	5	—
Prior years decreases	(23)	—
Balance, December 31, 2014	$ 34	$ 3
Current year increases	3	—
Prior years increases	7	5
Prior years decreases	(10)	—
Balance, December 31, 2015	$ 34	$ 8

FirstEnergy recognizes interest expense or income and penalties related to uncertain tax positions in income taxes. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy's reversal of accrued interest associated with unrecognized tax benefits reduced FirstEnergy's effective tax rate in 2015 and 2014 by approximately $1 million and $6 million, respectively. There was an increase of $1 million of accrued interest for the year ended December 31, 2013.

The following table summarizes the net interest expense (income) for the three years ended December 31, 2015 and the cumulative net interest payable as of December 31, 2015 and 2014 (FES did not have net interest expense (income) or a net interest payable for the periods presented):

	Net Interest Expense (Income) For the Years Ended December 31,			**Net Interest Payable As of December 31,**	
	2015	**2014**	**2013**	**2015**	**2014**
		(In millions)		*(In millions)*	
FirstEnergy	$ (1)	$ (6)	$ 1	$ 1	$ 2

General Taxes

	2015	2014	2013
		(In millions)	
FirstEnergy			
KWH excise	$ 193	$ 194	$ 219
State gross receipts	224	226	240
Real and personal property	410	393	368
Social security and unemployment	119	112	110
Other	32	37	41
Total general taxes	$ 978	$ 962	$ 978
FES			
State gross receipts	$ 44	$ 69	$ 77
Real and personal property	36	39	40
Social security and unemployment	16	17	19
Other	2	3	2
Total general taxes	$ 98	$ 128	$ 138

6. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years, expiring in 2016. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years expiring in 2017. OE, CEI and TE have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years, expiring in 2040. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. In 2013, FG acquired the remaining lessor interests in Bruce Mansfield Units 1, 2 and 3, which were part of the leases entered into by CEI and TE in 1987.

In February 2014, NG purchased 47.7 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. In November 2014, NG repurchased 55.3 MW of lessor equity interests in OE's existing sale and leaseback of Perry Unit 1 for approximately $87 million. OE and TE continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. During 2013, the investments held at Shippingport were liquidated. The PNBV arrangements effectively reduce lease costs related to those transactions (see Note 8, Variable Interest Entities).

As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

Operating lease expense for 2015, 2014 and 2013, is summarized as follows:

(In millions)	2015	2014	2013
FirstEnergy	$ 174	$ 199	$ 224
FES	$ 94	$ 95	$ 97

The future minimum capital lease payments as of December 31, 2015 are as follows:

Capital leases	**FirstEnergy**	**FES**
	(In millions)	
2016	$ 36	$ 6
2017	31	6
2018	24	2
2019	18	—
2020	14	—
Years thereafter	27	—
Total minimum lease payments	150	14
Interest portion	(18)	(1)
Present value of net minimum lease payments	132	13
Less current portion	32	5
Noncurrent portion	$ 100	$ 8

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2015, are as follows:

Operating Leases	FirstEnergy Lease Payments	PNBV	Net
		(In millions)	
2016	$ 197	$ 13	$ 184
2017	122	3	119
2018	135	—	135
2019	116	—	116
2020	91	—	91
Years thereafter	1,438	—	1,438
Total minimum lease payments	$ 2,099	$ 16	$ 2,083

FES' future minimum operating lease payments as of December 31, 2015, are as follows:

Operating Leases	Lease Payments
	(In millions)
2016	$ 131
2017	82
2018	101
2019	97
2020	68
Years thereafter	1,315
Total minimum lease payments	$ 1,794

7. INTANGIBLE ASSETS

As of December 31, 2015, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

	Intangible Assets			Amortization Expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2015	2016	2017	2018	2019	2020	Thereafter
NUG contracts[(1)]	$ 124	$ 25	$ 99	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 74
OVEC	54	9	45	2	2	2	2	2	2	35
Coal contracts[(2)(3)(4)]	556	430	126	116	38	32	17	17	6	—
FES customer contracts	148	87	61	17	17	16	14	13	1	—
	$ 882	$ 551	$ 331	$ 140	$ 62	$ 55	$ 38	$ 37	$ 14	$ 109

(1) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.

(2) A gross amount of $40 million ($23 million, net) of the coal contracts is related to FES. The 2015 and estimated 2016 to 2019 amortization expense for FES is $5.7 million annually.

(3) A gross amount of $102 million ($16 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings. Accordingly, the amortization expense for these coal contracts is excluded from table above.

(4) Amortization expense in 2015, includes a $67 million impairment of a coal contract intangible asset associated with the termination of a coal supply contract, which impacted earnings.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

8. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has (i) the power to direct the activities of a VIE that most significantly impact the entity's economic performance, and (ii) 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. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into categories based on similar risk characteristics and significance.

Consolidated VIEs

VIEs in which FirstEnergy is the primary beneficiary consist of the following (included in FirstEnergy's consolidated financial statements):

- ***PNBV*** - PNBV, a business trust established by OE in 1996, issued certain beneficial interests and notes to fund the acquisition of a portion of the bonds issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. The beneficial ownership of PNBV includes a 3% interest by unaffiliated third parties.
- ***Ohio Securitization*** - In September 2012, the Ohio Companies created separate, wholly-owned limited liability companies (SPEs) which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445 thousand that are recoverable through the usage-based charges. As of December 31, 2015 and December 31, 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.
- ***JCP&L Securitization*** - In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of December 31, 2015 and December 31, 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.
- ***MP and PE Environmental Funding Companies*** - The entities issued bonds of which the proceeds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2015 and December 31, 2014, $429 million and $450 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- ***Global Holding*** - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting. See Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

  As discussed in Note 15, Commitments, Guarantees and Contingencies, FE is the guarantor under Global Holding's $300 million term loan facility. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- ***PATH WV*** - PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.

- ***Power Purchase Agreements*** - FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production.

  FirstEnergy maintains 15 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

  Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $116 million and $185 million, respectively, during the years ended December 31, 2015 and 2014.

- ***Sale and Leaseback Transactions*** - FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements. As of December 31, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

  On June 24, 2014, OE exercised its irrevocable right to repurchase from the remaining owner participants the lessors' interests in Beaver Valley Unit 2 at the end of the lease term (June 1, 2017), which right to repurchase was assigned to NG. Additionally, on June 24, 2014, NG entered into a purchase agreement with an owner participant to purchase its lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 on May 23, 2016, which is just prior to the end of the lease term. Upon the completion of these transactions, NG will have obtained all of the lessor equity interests at Perry Unit 1 and Beaver Valley Unit 2.

  FES and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of December 31, 2015:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
		(In millions)	
FirstEnergy	$ 1,225	$ 950	$ 275
FES	$ 1,155	$ 933	$ 222

9. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation processes for FTRs and NUGs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 10, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWHs. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWHs reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWHs. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2015, from those used as of December 31, 2014. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2015 and 2014. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				(In millions)				
Corporate debt securities	$ —	$ 1,245	$ —	$ 1,245	$ —	$ 1,221	$ —	$ 1,221
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	8	8	—	—	39	39
Derivative assets - NUG contracts(1)	—	—	1	1	—	—	2	2
Equity securities(2)	576	—	—	576	592	—	—	592
Foreign government debt securities	—	75	—	75	—	76	—	76
U.S. government debt securities	—	180	—	180	—	182	—	182
U.S. state debt securities	—	246	—	246	—	237	—	237
Other(3)	105	212	—	317	55	256	—	311
Total assets	$ 685	$ 2,182	$ 9	$ 2,876	$ 648	$ 2,143	$ 41	$ 2,832
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(13)	(13)	—	—	(14)	(14)
Derivative liabilities - NUG contracts(1)	—	—	(137)	(137)	—	—	(153)	(153)
Total liabilities	$ (9)	$ (122)	$ (150)	$ (281)	$ (26)	$ (141)	$ (167)	$ (334)
Net assets (liabilities)(4)	$ 676	$ 2,060	$ (141)	$ 2,595	$ 622	$ 2,002	$ (126)	$ 2,498

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(3) Primarily consists of cash and short-term cash investments.
(4) Excludes $7 million and $40 million as of December 31, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2015 and December 31, 2014:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2014 Balance	$ 20	$ (222)	$ (202)	$ 4	$ (12)	$ (8)
Unrealized gain (loss)	2	(2)	—	47	(1)	46
Purchases	—	—	—	26	(16)	10
Settlements	(20)	71	51	(38)	15	(23)
December 31, 2014 Balance	$ 2	$ (153)	$ (151)	$ 39	$ (14)	$ 25
Unrealized gain (loss)	2	(49)	(47)	(5)	(7)	(12)
Purchases	—	—	—	22	(11)	11
Settlements	(3)	65	62	(48)	19	(29)
December 31, 2015 Balance	$ 1	$ (137)	$ (136)	$ 8	$ (13)	$ (5)

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (5)	Model	RTO auction clearing prices	($3.90) to $6.90	$1.00	Dollars/MWH
NUG Contracts	$ (136)	Model	Generation Regional electricity prices	400 to 3,871,000 $38.10 to $45.60	839,000 $40.20	MWH Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$ —	$ 678	$ —	$ 678	$ —	$ 655	$ —	$ 655
Derivative assets - commodity contracts	4	224	—	228	1	171	—	172
Derivative assets - FTRs	—	—	5	5	—	—	27	27
Equity securities[1]	378	—	—	378	360	—	—	360
Foreign government debt securities	—	59	—	59	—	57	—	57
U.S. government debt securities	—	23	—	23	—	46	—	46
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[2]	—	184	—	184	—	199	—	199
Total assets	$ 382	$ 1,172	$ 5	$ 1,559	$ 361	$ 1,132	$ 27	$ 1,520
Liabilities								
Derivative liabilities - commodity contracts	$ (9)	$ (122)	$ —	$ (131)	$ (26)	$ (141)	$ —	$ (167)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(13)	(13)
Total liabilities	$ (9)	$ (122)	$ (11)	$ (142)	$ (26)	$ (141)	$ (13)	$ (180)
Net assets (liabilities)[3]	$ 373	$ 1,050	$ (6)	$ 1,417	$ 335	$ 991	$ 14	$ 1,340

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $1 million and $44 million as of December 31, 2015 and December 31, 2014, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2015 and December 31, 2014:

	Derivative Asset	Derivative Liability	Net Asset/(Liability)
		(In millions)	
January 1, 2014 Balance	$ 3	$ (11)	$ (8)
Unrealized gain (loss)	34	(1)	33
Purchases	15	(16)	(1)
Settlements	(25)	15	(10)
December 31, 2014 Balance	$ 27	$ (13)	$ 14
Unrealized gain (loss)	2	(5)	(3)
Purchases	9	(10)	(1)
Settlements	(33)	17	(16)
December 31, 2015 Balance	$ 5	$ (11)	$ (6)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (6)	Model	RTO auction clearing prices	($3.90) to $5.70	$0.70	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and AFS securities.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. The NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset in net regulatory assets.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of December 31, 2015 and December 31, 2014:

	December 31, 2015[(1)]			December 31, 2014[(2)]		
	Cost Basis	**Unrealized Gains**	**Fair Value**	**Cost Basis**	**Unrealized Gains**	**Fair Value**
			(In millions)			
Debt securities						
FirstEnergy	$ 1,778	$ 16	$ 1,794	$ 1,724	$ 27	$ 1,751
FES	801	9	810	788	13	801
Equity securities						
FirstEnergy	$ 542	$ 34	$ 576	$ 533	$ 58	$ 591
FES	354	24	378	329	31	360

(1) Excludes short-term cash investments: FE Consolidated - $157 million; FES - $139 million.
(2) Excludes short-term cash investments: FE Consolidated - $241 million; FES - $204 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2015, 2014 and 2013 were as follows:

December 31, 2015	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**OTTI**	**Interest and Dividend Income**
			(In millions)		
FirstEnergy	$ 1,534	$ 209	$ (191)	$ (102)	$ 101
FES	733	158	(134)	(90)	57

December 31, 2014	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**OTTI**	**Interest and Dividend Income**
			(In millions)		
FirstEnergy	$ 2,133	$ 146	$ (75)	$ (37)	$ 96
FES	1,163	113	(54)	(33)	56

December 31, 2013	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**OTTI**	**Interest and Dividend Income**
			(In millions)		
FirstEnergy	$ 2,047	$ 92	$ (46)	$ (90)	$ 101
FES	940	70	(21)	(79)	60

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2015 and December 31, 2014:

	December 31, 2015			December 31, 2014		
	Cost Basis	**Unrealized Gains**	**Fair Value**	**Cost Basis**	**Unrealized Gains**	**Fair Value**
			(In millions)			
Debt Securities						
FirstEnergy	$ 6	$ 2	$ 8	$ 13	$ 4	$ 17

The held-to-maturity debt securities contractually mature by June 30, 2017. Investments in employee benefit trusts and equity method investments totaling $255 million as of December 31, 2015 and $626 million as of December 31, 2014, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$ 20,244	$ 21,519	$ 19,828	$ 21,733
FES	3,027	3,121	3,097	3,241

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2015 and December 31, 2014.

10. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility related to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value (unless they meet the normal purchases and normal sales criteria) as follows:

- Changes in the fair value of derivative instruments that are designated and qualify as cash flow hedges are recorded to AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.
- Changes in the fair value of derivative instruments that are designated and qualify as fair value hedges are recorded as an adjustment to the item being hedged. When fair value hedges are discontinued, the adjustment recorded to the item being hedged is amortized into earnings.
- Changes in the fair value of derivative instruments that are not designated in a hedging relationship are recorded in earnings on a mark-to-market basis, unless otherwise noted.

Derivative instruments meeting the normal purchases and normal sales criteria are accounted for under the accrual method of accounting with their effects included in earnings at the time of contract performance.

FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates.

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $11 million and $8 million as of December 31, 2015 and December 31, 2014, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $1 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $42 million and $50 million as of December 31, 2015 and December 31, 2014, respectively. Based on current estimates, approximately $9 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to Note 2, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as cash flow hedges.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. As of December 31, 2015 and December 31, 2014, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $20 million and $32 million as of December 31, 2015 and December 31, 2014, respectively. During the next twelve months, approximately $10 million of unamortized gains is expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $12 million during the years ended December 31, 2015 and 2014.

As of December 31, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2015, FirstEnergy's net asset position under commodity derivative contracts was $97 million, which related to FES positions. Under these commodity derivative contracts, FES posted $26 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $3 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on derivative contracts held as of December 31, 2015, an increase in commodity prices of 10% would decrease net income by approximately $30 million during the next twelve months.

Interest Rate Swaps

As of December 31, 2015 and 2014, no interest rate swaps were outstanding.

NUGs

As of December 31, 2015, FirstEnergy's net liability position under NUG contracts was $136 million representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of December 31, 2015, FirstEnergy's and FES' net liability position under FTRs was $5 million and $6 million, respectively and FES posted $6 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from PJM. PJM has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to PJM, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's Utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets			**Derivative Liabilities**		
	Fair Value			**Fair Value**	
	December 31, 2015	**December 31, 2014**		**December 31, 2015**	**December 31, 2014**
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 150	$ 121	Commodity Contracts	$ (94)	$ (154)
FTRs	7	38	FTRs	(12)	(13)
	157	159		(106)	(167)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs[1]	(137)	(153)
Commodity Contracts	78	51	**Noncurrent Liabilities - Other**		
FTRs	1	1	Commodity Contracts	(37)	(13)
NUGs[1]	1	2	FTRs	(1)	(1)
	80	54		(175)	(167)
Derivative Assets	$ 237	$ 213	**Derivative Liabilities**	$ (281)	$ (334)

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative assets and derivative liabilities on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

December 31, 2015	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 228	$ (125)	$ —	$ 103
FTRs	8	(8)	—	—
NUG contracts	1	—	—	1
	$ 237	$ (133)	$ —	$ 104
Derivative Liabilities				
Commodity contracts	$ (131)	$ 125	$ 3	$ (3)
FTRs	(13)	8	5	—
NUG contracts	(137)	—	—	(137)
	$ (281)	$ 133	$ 8	$ (140)

December 31, 2014	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 172	$ (126)	$ —	$ 46
FTRs	39	(14)	—	25
NUG contracts	2	—	—	2
	$ 213	$ (140)	$ —	$ 73
Derivative Liabilities				
Commodity contracts	$ (167)	$ 126	$ 35	$ (6)
FTRs	(14)	14	—	—
NUG contracts	(153)	—	—	(153)
	$ (334)	$ 140	$ 35	$ (159)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2015:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	16	49	(33)	MWH
FTRs	29	—	29	MWH
NUGs	4	—	4	MWH
Natural Gas	83	—	83	mmBTU

The effect of active derivative instruments not in a hedging relationship on the Consolidated Statements of Income during 2015 and 2014 are summarized in the following tables:

	Year Ended December 31,		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[1]	$ 93	$ (20)	$ 73
Realized Gain (Loss) Reclassified to:			
Revenues[2]	$ 111	$ 50	$ 161
Purchased Power Expense[3]	(130)	—	(130)
Other Operating Expense[4]	—	(49)	(49)
Fuel Expense	(34)	—	(34)

[1] Includes $93 million for commodity contracts and ($19) million for FTRs associated with FES.

[2] Includes $111 million for commodity contracts and $49 million for FTRs associated with FES.

[3] Includes ($130) million for commodity contracts associated with FES.

[4] Includes ($49) million for FTRs associated with FES.

	Year Ended December 31,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[5]	$ (86)	$ 22	$ —	$ (64)
Realized Gain (Loss) Reclassified to:				
Revenues[6]	$ (6)	$ 68	$ —	$ 62
Purchased Power Expense[7]	365	—	—	365
Other Operating Expense[8]	—	(44)	—	(44)
Fuel Expense	(6)	—	—	(6)
Interest Expense	—	—	14	14

[5] Includes ($86) million for commodity contracts and $21 million for FTRs associated with FES.

[6] Includes ($6) million for commodity contracts and $67 million for FTRs associated with FES.

[7] Realized losses on financially settled wholesale sales contracts of $252 million resulting from higher market prices were netted in purchased power. Includes $365 million for commodity contracts associated with FES.

[8] Includes ($43) million for FTRs associated with FES.

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during 2015 and 2014. Changes in the value of these contracts are deferred for future recovery from (or credit to) customers:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Year Ended December 31, NUGs	Regulated FTRs	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2015	$ (151)	$ 11	$ (140)
Unrealized loss	(47)	(9)	(56)
Purchases	—	12	12
Settlements	62	(13)	49
Outstanding net asset (liability) as of December 31, 2015	$ (136)	$ 1	$ (135)
Outstanding net liability as of January 1, 2014	$ (202)	$ —	$ (202)
Unrealized gain (loss)	(1)	13	12
Purchases	—	11	11
Settlements	52	(13)	39
Outstanding net asset (liability) as of December 31, 2014	$ (151)	$ 11	$ (140)

11. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2015, FirstEnergy's unrestricted retained earnings were $2.3 billion. Dividends declared in 2015 and 2014 were $1.44 per share, which included dividends of $0.36 per share paid in the first, second, third and fourth quarters. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors. On January 19, 2016 the Board of Directors declared a quarterly dividend of $0.36 per share to be paid in the first quarter of 2016.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to their respective parents from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 45%. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' abilities to pay cash dividends to FirstEnergy as of December 31, 2015.

Stock Issuance

In each of 2015 and 2014, FE issued approximately 2.5 million shares of common stock to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan and certain share-based benefit plans.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2015, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$ 100		
OE	6,000,000	$ 100	8,000,000	no par
OE	8,000,000	$ 25		
Penn	1,200,000	$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$ 100	5,000,000	$ 25
TE	12,000,000	$ 25		
JCP&L	15,600,000	no par		
ME	10,000,000	no par		
PN	11,435,000	no par		
MP	940,000	$ 100		
PE	10,000,000	$ 0.01		
WP	32,000,000	no par		

As of December 31, 2015, and 2014, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2015 and 2014:

	As of December 31, 2015		As of December 31	
(Dollar amounts in millions)	Maturity Date	Interest Rate	2015	2014
FirstEnergy:				
FMBs	2016 - 2045	3.340% - 9.740%	$ 3,269	$ 3,190
Secured notes - fixed rate	2016 - 2037	0.679% - 12.000%	2,096	2,247
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			2,098	2,247
Unsecured notes - fixed rate	2016 - 2045	2.150% - 7.700%	13,580	13,078
Unsecured notes - variable rate	2017 - 2020	0.010% - 2.180%	1,292	1,292
Total unsecured notes			14,872	14,370
Capital lease obligations			132	160
Unamortized debt discounts			(18)	(8)
Unamortized fair value adjustments			5	21
Currently payable long-term debt			(1,166)	(804)
Total long-term debt and other long-term obligations			$ 19,192	$ 19,176
FES:				
Secured notes - fixed rate	2016 - 2018	5.625% - 12.000%	$ 340	$ 437
Secured notes - variable rate	2017 - 2017	3.500% - 3.500%	2	—
Total secured notes			342	437
Unsecured notes - fixed rate	2016 - 2039	2.150% - 6.800%	2,593	2,568
Unsecured notes - variable rate	2017 - 2017	0.010% - 0.010%	92	92
Total unsecured notes			2,685	2,660
Capital lease obligations			13	18
Unamortized debt discounts			(1)	(1)
Currently payable long-term debt			(512)	(506)
Total long-term debt and other long-term obligations			$ 2,527	$ 2,608

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

In August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L's short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also, in the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

In October 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, in October 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

See Note 6, Leases for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. As of December 31, 2015 and 2014, $429 million and $450 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include transition bonds issued by JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. The proceeds were used to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. As of December 31, 2015 and 2014, $128 million and $168 million of the transition bonds were outstanding, respectively.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. As of December 31, 2015 and 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.

See Note 8, Variable Interest Entities for additional information on securitized bonds.

Other Long-term Debt

The Ohio Companies, Penn, FG and NG each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2015, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $3 million in 2015, all of which relate to Penn. Penn expects to meet its 2016 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2015, FirstEnergy's currently payable long-term debt included approximately $92 million of FES variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2015. PCRBs that are scheduled to be tendered for mandatory purchase prior to maturity are reflected in the applicable year in which such PCRBs are scheduled to be tendered.

Year	FirstEnergy	FES
	(In millions)	
2016	$ 1,039	$ 414
2017	1,733	257
2018	1,702	516
2019	2,268	322
2020	1,231	667

The following table classifies the outstanding fixed rate PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

Year	FirstEnergy	FES
	(In millions)	
2016	$ 391	$ 391
2017	222	222
2018	375	375
2019	232	232
2020	490	490

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG is entitled to a credit against its obligation to repay those bonds. FG pays annual fees based on the amounts of the LOCs to the issuing bank and is obligated to reimburse the bank for any drawings thereunder.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2015, are as follows:

	Aggregate LOC Amount [1]	Annual Fees
	(In millions)	
FirstEnergy	$ 93	1.25%
FES	93	1.25%

(1) Includes approximately $1 million of applicable interest coverage.

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2015, FirstEnergy and FES remain in compliance with all debt covenant provisions.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FE financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FE. Also, defaults by FE would generally not cross-default applicable financing arrangements of any of FE's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FE, FG, NG or the Utilities.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities), which are available until March 31, 2019. FirstEnergy had $1,708 million and $1,799 million of short-term borrowings as of December 31, 2015 and 2014, respectively. FirstEnergy's available liquidity under the Facilities as of January 31, 2016 was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$ 3,500	$ 1,595
FES / AE Supply	Revolving	March 2019	1,500	1,442
FET[2]	Revolving	March 2019	1,000	1,000
		Subtotal	$ 6,000	$ 4,037
		Cash	—	63
		Total	$ 6,000	$ 4,100

(1) FE and the Utilities
(2) Includes FET, ATSI and TrAIL as subsidiary borrowers

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2015:

Borrower	Revolving Credit Facility Sub-Limits	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FE	$ 3,500	$ — (1)
FES	1,500	— (2)
AE Supply	1,000	— (2)
FET	1,000	— (1)
OE	500	500 (3)
CEI	500	500 (3)
TE	500	500 (3)
JCP&L	600	500 (3)
ME	300	500 (3)
PN	300	300 (3)
WP	200	200 (3)
MP	500	500 (3)
PE	150	150 (3)
ATSI	500	500 (3)
Penn	50	100 (3)
TrAIL	400	400 (3)

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $600 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of December 31, 2015, the borrowers were in compliance with the applicable debt to total capitalization ratio covenants under the respective Facilities.

Term Loans

FE has a $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. The proceeds from this term loan reduced borrowings under the FE Facility. Additionally, FE has a $200 million variable rate term loan with a maturity date of May 29, 2020. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of December 31, 2015, FE was in compliance with the applicable consolidated debt to total capitalization ratio covenants under each of these term loans.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2015 was 0.84% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2015 and 2014, were as follows:

	2015	2014
FirstEnergy	2.16%	1.96%
FES	—%	3.34%

13. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2015 and 2014 were as follows:

	2015	2014
	(In millions)	
FirstEnergy	$ 2,282	$ 2,341
FES	$ 1,327	$ 1,365

The following table summarizes the changes to the ARO balances during 2015 and 2014:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2014	$ 1,678	$ 1,015
Liabilities settled	(9)	(7)
Accretion	113	66
Revisions in estimated cash flows	(395)	(233)
Balance, December 31, 2014	$ 1,387	$ 841
Liabilities settled	(13)	(8)
Accretion	92	55
Revisions in estimated cash flows	(56)	(57)
Balance, December 31, 2015	$ 1,410	$ 831

During 2015, FE and FES reduced its ARO by $57 million based on the results of decommissioning cost studies for the Davis-Besse and Perry nuclear generating stations.

During 2014, based on studies by a third-party to reassess the estimated costs of decommissioning certain nuclear generating facilities, FE decreased its ARO by $395 million ($233 million at FES) of which $133 million was credited against a regulatory asset associated with nuclear decommissioning and spent fuel disposal costs for TMI-2. The decrease in the ARO primarily resulted from an extension in the number of years in which decommissioning activities are estimated to occur at Davis-Besse, Perry, TMI-2 and Beaver Valley Units 1 and 2.

14. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. PE recovers its costs plus a return for providing SOS.

The Maryland legislature adopted a statute in 2008 codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $19 million was incurred through December 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date, such recovery has not been sought or obtained by PE. On January 28, 2016, PE filed a request to increase plan spending by $2 million in order to reach the new goals for 2017 set in the July 16, 2015 order.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would require approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. On July 1, 2014, the Staff of the MDPSC issued a set of reports that recommended the imposition of extensive additional requirements in the areas of storm response, feeder performance, estimates of restoration times, and regulatory reporting. The Staff of the MDPSC also recommended the imposition of penalties, including customer rebates, for a utility's failure or inability to comply with the escalating standards of storm restoration speed proposed by the Staff of the MDPSC. In addition, the Staff of the MDPSC proposed that the utilities be required to develop and implement system hardening plans, up to a rate impact cap on cost. The MDPSC conducted a hearing September 15-18, 2014, to consider certain of these matters, and has not yet issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels. The proposed regulations incorporating the new SAIDI and SAIFI standards were approved as final in December 2015.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC's regulations. The MDPSC conducted hearings on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015 and subsequently closed its 2014 service reliability review.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. On January 8, 2016, the NJBPU President issued an Order granting Rate Counsel's Motion on the legal issue of whether MAIT can be designated as a public utility. The procedural schedule has been suspended until a decision is made on this issue. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operate under their ESP 3 plan which expires on May 31, 2016. The material terms of ESP 3 include:

- A base distribution rate freeze through May 31, 2016;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- A requirement to provide power to non-shopping customers at a market-based price set through an auction process;

- Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Notices of appeal of the Ohio Companies' ESP 3 plan to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. The oral argument in this matter occurred on January 6, 2016.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled *Powering Ohio's Progress*. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015. The evidentiary hearing on the ESP IV commenced on August 31, 2015 and concluded on October 29, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories. The PUCO completed a hearing on the Third Supplemental Stipulation and Recommendation in January 2016. Initial briefs are due on February 16, 2016 and reply briefs are due on February 26, 2016. A final PUCO decision is expected in March 2016.

The proposed ESP IV supports FirstEnergy's strategic focus on regulated operations and better positions the Ohio Companies to deliver on their ongoing commitment to upgrade, modernize and maintain reliable electric service for customers while preserving electric security in Ohio. The material terms of the proposed ESP IV, as modified by the stipulations include:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through a proposed eight-year FERC-jurisdictional PPA for the output of the Sammis and Davis-Besse plants and FES' share of OVEC against the revenues received from selling such output into the PJM markets over the same period, subject to the PUCO's termination of Rider RRS charges/credits associated with any plants or units that may be sold or transferred;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers;
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio;
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers;
- An agreement to file by February 29, 2016, a Grid Modernization Business Plan for PUCO consideration and approval;
- A contribution of $3 million per year ($24 million over the eight year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory;
- Contributions of $2.4 million per year ($19 million over the eight year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers; and
- A contribution of $1 million per year ($8 million over the eight year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On January 27, 2016, certain parties filed a complaint at FERC against FES, OE, CEI, and TE that requests FERC review of the ESP IV PPA under Section 205 of the FPA. In addition to such proceeding, parties have expressed an intention to challenge in the courts and/or before FERC, the PPA or PUCO approval of the ESP IV, if approved. Management intends to vigorously defend against such challenges.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to legislative amendments to the energy efficiency standards discussed below. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to legislative amendments to the peak demand reduction standards discussed below.

On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state. No legislation has yet been introduced to change the standards described above.

On March 20, 2013, the PUCO approved the three-year energy efficiency portfolio plans for 2013-2015, originally estimated to cost the Ohio Companies approximately $250 million over the three-year period, which is expected to be recovered in rates. Actual costs may be lower for a number of reasons including the approval of the amended portfolio plan under SB310. On July 17, 2013, the PUCO modified the plan to authorize the Ohio Companies to receive 20% of any revenues obtained from offering energy efficiency and DR reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. ELPC and OCC filed applications for rehearing, which were granted for the sole purpose of further consideration of the issue. On September 24, 2014, the Ohio Companies filed an amendment to their portfolio plan as contemplated by SB310, seeking to suspend certain programs for the 2015-2016 period in order to better align the plan with the new benchmarks under SB310. On November 20, 2014, the PUCO approved the Ohio Companies' amended portfolio plan. Several applications for rehearing were filed, and the PUCO granted those applications for further consideration of the matters specified in those applications.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with, and are not supported by, statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal, which is still pending. The matter has not been scheduled for oral argument.

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to legislative amendments discussed above, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013, approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for certain purchases arising from one auction and directed the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN and Penn.

On November 3, 2015, the Pennsylvania Companies filed their proposed DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the proposed programs, the supply would be provided by wholesale suppliers though a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the proposal includes modifications to the Pennsylvania Companies' existing POR programs in order to reduce the level of uncollectibles the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement that resolves all issues in the proceeding and is subject to PPUC approval.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies as discussed below. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. The DSIC riders are expected to be effective July 1, 2016.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provided for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the approved settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 a revised implementation plan regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. The Pennsylvania Companies filed their revised implementation plan in compliance with this order. A final order adopting the plan, as revised, was entered on November 5, 2015. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provided for: a $15 million increase in annual base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a five-year period through base rates approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which would be a 12.5% overall increase over existing rates. The original proposed increase was comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A settlement was reached among all the parties increasing revenues $96.9 million and deferring other costs for recovery into 2017. The settlement was presented to the WVPSC on November 19, 2015, and a final order approving the settlement without changes was issued on December 22, 2015, with rates effective on January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates over a two year period, which is a 2.8% overall increase over existing rates. The proposed increase was comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. A settlement was reached among all the parties increasing revenues $36.7 million annually for the 2016-2017 two year rate recovery period, and was presented to the WVPSC on November 19, 2015. A final order approving the settlement without changes was issued on December 21, 2015, with rates effective on January 1, 2016.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, NG, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such occurrences are found, FirstEnergy develops information about the occurrence and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an occurrence to RFC. Moreover, it is clear that NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk electric system could result in the imposition of financial penalties, and obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocate for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, where each customer in the zone would pay based on its total usage of energy within PJM. This question has been the subject of extensive litigation before FERC and the appellate courts, including before the Seventh Circuit. On June 25, 2014, a divided three-judge panel of the Seventh Circuit ruled that FERC had not quantified the benefits that western PJM utilities would derive from certain new 500 kV or higher lines and thus had not adequately supported its decision to socialize the costs of these lines. The majority found that eastern PJM utilities are the primary beneficiaries of the lines, while western PJM utilities are only incidental beneficiaries, and that, while incidental beneficiaries should pay some share of the costs of the lines, that share should be proportionate to the benefit they derive from the lines, and not on load-ratio share in PJM as a whole. The court remanded the case to FERC, which issued an order setting the issue of cost allocation for hearing and settlement proceedings. Settlement discussions under a FERC-appointed settlement judge are ongoing.

In a series of orders in certain Order No. 1000 dockets, FERC asserted that the PJM transmission owners do not hold an incumbent "right of first refusal" to construct, own and operate transmission projects within their respective footprints that are approved as part of PJM's RTEP process. FirstEnergy and other PJM transmission owners have appealed these rulings, and the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No. 1000 compliance filing.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the transfer to PJM. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement remains pending.

Separately, the question of ATSI's responsibility for certain costs for the "Michigan Thumb" transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings before FERC and certain United States appellate courts. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which is pending at FERC. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. Certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC's prior ruling rejecting MISO's proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. The briefs and replies thereto are now before FERC for consideration.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, is pending before FERC as a result of the Seventh Circuit's June 25, 2014 order described above under PJM Transmission Rates.

The outcome of the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate from an "historical looking" approach, where transmission rates reflect actual costs for the prior year, to a "forward looking" approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, subject to refund and the outcome of hearing and settlement proceedings. FERC subsequently issued an order on October 29, 2015, accepting a settlement agreement on the forward-looking formula rate, subject to minor compliance requirements. The settlement agreement provides for certain changes to ATSI's formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% from January 1, 2015 through June 30, 2015; (ii) 11.06% from July 1, 2015 through December 31, 2015; and (iii) 10.38% from January 1, 2016, unless changed pursuant to section 205 or 206 of the FPA, provided the effective date for any change cannot be earlier than January 1, 2018.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of: (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected during the first quarter of 2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. Requests for rehearing or clarification of FERC's November 3, 2015 order by various parties, including AE Supply, remain pending.

In another proceeding, in May 2009, the California Attorney General, on behalf of certain California parties, filed a complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during

2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply and other parties filed motions to dismiss, which FERC granted. The California Attorney General appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto are now before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

FERC Opinion No. 531

On June 19, 2014, FERC issued Opinion No. 531, in which FERC revised its approach for calculating the discounted cash flow element of FERC's ROE methodology, and announced the potential for a qualitative adjustment to the ROE methodology results. Under the old methodology, FERC used a five-year forecast for the dividend growth variable, whereas going forward the growth variable will consist of two parts: (a) a five-year forecast for dividend growth (2/3 weight); and (b) a long-term dividend growth forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median of the "zone of reasonableness" that came out of the ROE formula, whereas going forward, FERC may rely on record evidence to make qualitative adjustments to the outcome of the ROE methodology in order to reach a level sufficient to attract future investment. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. FirstEnergy is evaluating the potential impact of Opinion No. 531 on the authorized ROE of our FERC-regulated transmission utilities and the cost-of-service wholesale power generation transactions of MP.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the complaint, and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

In August and September 2015, PJM conducted RPM auctions pursuant to the new Capacity Performance rules. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On January 25, 2016, the United States Supreme Court reversed the opinion of the U.S. Court of Appeals for the D.C. Circuit and remanded for further action, finding FERC has statutory authority under the FPA to regulate compensation of demand response resources in FERC-jurisdictional wholesale power markets. The United States Supreme Court also reversed the holding that FERC's Order No. 745 was arbitrary and capricious, finding that the order included detailed support of the chosen compensation method.

On May 23, 2014, as amended September 22, 2014, FESC, on behalf of its affiliates with market-based rate authorization, filed a complaint asking FERC to issue an order requiring the removal of all portions of the PJM Tariff allowing or requiring DR to be included in the PJM capacity market, with a refund effective date of May 23, 2014. FESC also requested that the results of the May 2014 PJM BRA be considered void and legally invalid to the extent that DR cleared that auction because the participation of DR in that auction was unlawful. However, in light of the United States Supreme Court's January 25, 2016 decision discussed above, on January 29, 2016, FESC withdrew the complaint.

15. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.5 billion (assuming 103 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.1 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (NG-$501 million) per incident but not more than $76 million (NG-$75 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable annually, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.96 billion (NG-$1.93 billion) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $15 million (NG-$15 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $83 million (NG-$81 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of December 31, 2015, outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting of parental guarantees ($583 million), subsidiaries' guarantees ($2,137 million), other guarantees ($300 million) and other assurances ($667 million).

Of this aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2015, FES has posted collateral of $188 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 198	$ 6	$ 41	$ 245
BB+/Ba1 Credit Ratings	$ 231	$ 6	$ 41	$ 278
Full impact of credit contingent contractual obligations	$ 363	$ 16	$ 41	$ 420

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of December 31, 2015, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES would be required to post $8 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with Global Holding's term loan facility, a portion of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with each of FEV's and WMB Marketing Ventures,LLC's 33-1/3% membership interests in Global Holding, are pledged to the lenders under Global Holding's facility as collateral. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FirstEnergy to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 8, Variable Interest Entities, and Note 1, Organization, Basis of Presentation and Significant Accounting Policies - Investments, for additional information regarding FEV's investment in Global Holding.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act

FirstEnergy complies with SO_2 and NOx emission reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but EPA will designate those counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCl for all existing and new fossil fuel fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants plants. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. The U.S. Court of Appeals for the D.C. Circuit later remanded MATS back to EPA, who represented to such court that the EPA is on track to issue a finalized MATS by April 15, 2016. Subject to the outcome of any further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $202 million has been spent through December 31, 2015 ($80 million at CES and $122 million at Regulated Distribution).

As a result of MATS, Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. The arbitration panel has determined to consolidate the claims with a liability hearing expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls to the deactivated plant, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO_2 emissions will be reduced 25% below 2005 levels by 2015, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a two-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. The Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

The EPA finalized CWA Section 316(b) regulations in May 2014, requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement when aquatic organisms are pinned against screens or other parts of a cooling water intake system to a 12% annual average and requiring cooling water intake structures exceeding 125 million gallons per day to conduct studies to determine site-specific controls, if any, to reduce entrainment, which occurs when aquatic life is drawn into a facility's cooling water system. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore plant's cooling water intake channel to divert fish away from the plant's cooling water intake system. Depending on the results of such studies and any final action taken by the states based on those studies, the future capital costs of compliance with these standards may be substantial.

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of the appeal or estimate the possible loss or range of loss.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2014, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to assure the safe disposal of CCRs from electric generating plants. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield's Ferry CCR disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of December 31, 2015 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $126 million have been accrued through December 31, 2015. Included in the total are accrued liabilities of approximately $87 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the loss or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request to reopen the record and admit a contention on the NRC's Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC's failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance. FENOC plans to submit a license amendment application related to the Shield Building analysis in 2016.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FirstEnergy's nuclear facilities.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 14, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

16. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for FES during the three years ended December 31, 2015 are as follows:

FES	**2015**	**2014**	**2013**
		(In millions)	
Revenues:			
Electric sales to affiliates	$ 664	$ 861	$ 652
Other	6	6	6
Expenses:			
Purchased power from affiliates	353	271	486
Fuel	1	1	—
Support services	705	619	619
Investment Income:			
Interest income from FE	2	3	2
Interest Expense:			
Interest expense to affiliates	4	3	4
Interest expense to FE	3	4	6

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions are generally settled under commercial terms within thirty days. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES and the Utilities are parties to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 5, Taxes).

17. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2015, 2014, and 2013, Condensed Consolidating Balance Sheets as of December 31, 2015 and December 31, 2014, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2015, 2014, and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 4,824	$ 1,801	$ 2,138	$ (3,758)	$ 5,005
OPERATING EXPENSES:					
Fuel	—	679	192	—	871
Purchased power from affiliates	3,826	—	285	(3,758)	353
Purchased power from non-affiliates	1,684	—	—	—	1,684
Other operating expenses	399	275	618	49	1,341
Pension and OPEB mark-to-market adjustment	(8)	10	55	—	57
Provision for depreciation	12	124	191	(3)	324
General taxes	45	26	27	—	98
Total operating expenses	5,958	1,114	1,368	(3,712)	4,728
OPERATING INCOME (LOSS)	(1,134)	687	770	(46)	277
OTHER INCOME (EXPENSE):					
Investment income (loss), including net income from equity investees	844	17	(5)	(870)	(14)
Miscellaneous income	1	2	—	—	3
Interest expense — affiliates	(29)	(8)	(4)	34	(7)
Interest expense — other	(52)	(104)	(49)	58	(147)
Capitalized interest	—	6	29	—	35
Total other income (expense)	764	(87)	(29)	(778)	(130)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(370)	600	741	(824)	147
INCOME TAXES (BENEFITS)	(452)	224	278	15	65
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 82	$ 376	$ 463	$ (839)	$ 82
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	(9)	—	(8)	8	(9)
Other comprehensive loss	(18)	(5)	(8)	13	(18)
Income tax benefits on other comprehensive loss	(7)	(2)	(3)	5	(7)
Other comprehensive loss, net of tax	(11)	(3)	(5)	8	(11)
COMPREHENSIVE INCOME	$ 71	$ 373	$ 458	$ (831)	$ 71

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME (LOSS)					
REVENUES	$ 5,990	$ 1,902	$ 2,172	$ (3,920)	$ 6,144
OPERATING EXPENSES:					
Fuel	—	1,055	198	—	1,253
Purchased power from affiliates	3,920	—	271	(3,920)	271
Purchased power from non-affiliates	2,767	4	—	—	2,771
Other operating expenses	790	269	527	49	1,635
Pension and OPEB mark-to-market adjustment	19	90	188	—	297
Provision for depreciation	10	119	193	(3)	319
General taxes	72	31	25	—	128
Total operating expenses	7,578	1,568	1,402	(3,874)	6,674
OPERATING INCOME (LOSS)	(1,588)	334	770	(46)	(530)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(2)	—	(6)
Investment income, including net income from equity investees	791	8	61	(799)	61
Miscellaneous income	2	4	—	—	6
Interest expense — affiliates	(12)	(6)	(4)	15	(7)
Interest expense — other	(53)	(101)	(52)	60	(146)
Capitalized interest	—	4	30	—	34
Total other income (expense)	725	(92)	33	(724)	(58)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(863)	242	803	(770)	(588)
INCOME TAXES (BENEFITS)	(619)	87	298	6	(228)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(244)	155	505	(776)	(360)
Discontinued operations (net of income taxes of $70)	—	116	—	—	116
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$ (244)	$ 271	$ 505	$ (776)	$ (244)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(10)	—	—	—	(10)
Change in unrealized gain on available-for-sale securities	21	—	21	(21)	21
Other comprehensive income (loss)	5	(5)	21	(16)	5
Income taxes (benefits) on other comprehensive income (loss)	2	(2)	8	(6)	2
Other comprehensive income (loss), net of tax	3	(3)	13	(10)	3
COMPREHENSIVE INCOME (LOSS)	$ (241)	$ 268	$ 518	$ (786)	$ (241)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 6,068	$ 2,399	$ 1,634	$ (3,928)	$ 6,173
OPERATING EXPENSES:					
Fuel	—	1,056	206	—	1,262
Purchased power from affiliates	4,148	—	266	(3,928)	486
Purchased power from non-affiliates	2,326	7	—	—	2,333
Other operating expenses	635	275	529	48	1,487
Pension and OPEB mark-to-market adjustment	(8)	(37)	(36)	—	(81)
Provision for depreciation	6	127	178	(5)	306
General taxes	80	34	24	—	138
Total operating expenses	7,187	1,462	1,167	(3,885)	5,931
OPERATING INCOME (LOSS)	(1,119)	937	467	(43)	242
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income, including net income from equity investees	847	1	25	(857)	16
Miscellaneous income	4	24	—	—	28
Interest expense — affiliates	(13)	(5)	(6)	14	(10)
Interest expense — other	(63)	(104)	(54)	61	(160)
Capitalized interest	1	2	36	—	39
Total other income (expense)	673	(82)	1	(782)	(190)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(446)	855	468	(825)	52
INCOME TAXES (BENEFITS)	(506)	365	135	12	6
INCOME FROM CONTINUING OPERATIONS	60	490	333	(837)	46
Discontinued operations (net of income taxes of $8)	—	14	—	—	14
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(15)	(13)	—	13	(15)
Amortized gain on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available-for-sale securities	(8)	—	(8)	8	(8)
Other comprehensive loss	(29)	(13)	(8)	21	(29)
Income tax benefits on other comprehensive loss	(11)	(5)	(3)	8	(11)
Other comprehensive loss, net of tax	(18)	(8)	(5)	13	(18)
COMPREHENSIVE INCOME	$ 42	$ 496	$ 328	$ (824)	$ 42

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	275	—	—	—	275
Affiliated companies	433	403	461	(846)	451
Other	36	4	19	—	59
Notes receivable from affiliated companies	406	1,210	805	(2,410)	11
Materials and supplies	53	204	213	—	470
Derivatives	154	—	—	—	154
Collateral	70	—	—	—	70
Prepayments and other	48	18	—	—	66
	1,475	1,841	1,498	(3,256)	1,558
PROPERTY, PLANT AND EQUIPMENT:					
In service	93	6,367	8,233	(382)	14,311
Less — Accumulated provision for depreciation	40	2,144	3,775	(194)	5,765
	53	4,223	4,458	(188)	8,546
Construction work in progress	30	249	878	—	1,157
	83	4,472	5,336	(188)	9,703
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,327	—	1,327
Investment in affiliated companies	7,452	—	—	(7,452)	—
Other	—	10	—	—	10
	7,452	10	1,327	(7,452)	1,337
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	300	16	—	(316)	—
Customer intangibles	61	—	—	—	61
Goodwill	23	—	—	—	23
Property taxes	—	12	28	—	40
Derivatives	79	—	—	—	79
Other	33	318	21	12	384
	496	346	49	(304)	587
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ —	$ 229	$ 308	$ (25)	$ 512
Short-term borrowings-					
Affiliated companies	2,021	389	—	(2,410)	—
Other	—	8	—	—	8
Accounts payable-					
Affiliated companies	884	146	368	(856)	542
Other	21	118	—	—	139
Accrued taxes	7	93	62	(86)	76
Derivatives	103	1	—	—	104
Other	66	61	9	45	181
	3,102	1,045	747	(3,332)	1,562
CAPITALIZATION:					
Total equity	5,605	2,944	4,476	(7,420)	5,605
Long-term debt and other long-term obligations	694	2,122	847	(1,136)	2,527
	6,299	5,066	5,323	(8,556)	8,132
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	791	791
Accumulated deferred income taxes	6	—	697	(103)	600
Asset retirement obligations	—	191	640	—	831
Retirement benefits	27	305	—	—	332
Derivatives	37	1	—	—	38
Other	35	61	803	—	899
	105	558	2,140	688	3,491
	$ 9,506	$ 6,669	$ 8,210	$ (11,200)	$ 13,185

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	415	—	—	—	415
Affiliated companies	484	487	674	(1,120)	525
Other	66	21	20	—	107
Notes receivable from affiliated companies	339	838	272	(1,449)	—
Materials and supplies	67	202	223	—	492
Derivatives	147	—	—	—	147
Collateral	229	—	—	—	229
Prepayments and other	48	19	—	1	68
	1,795	1,569	1,189	(2,568)	1,985
PROPERTY, PLANT AND EQUIPMENT:					
In service	133	6,217	7,628	(382)	13,596
Less — Accumulated provision for depreciation	36	2,058	3,305	(191)	5,208
	97	4,159	4,323	(191)	8,388
Construction work in progress	3	206	801	—	1,010
	100	4,365	5,124	(191)	9,398
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,607	—	—	(6,607)	—
Other	—	10	—	—	10
	6,607	10	1,365	(6,607)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	284	98	—	(382)	—
Customer intangibles	78	—	—	—	78
Goodwill	23	—	—	—	23
Property taxes	—	14	27	—	41
Unamortized sale and leaseback costs	—	—	—	—	—
Derivatives	52	—	—	—	52
Other	34	277	7	13	331
	471	389	34	(369)	525
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 18	$ 164	$ 348	$ (24)	$ 506
Short-term borrowings-					
Affiliated companies	1,135	321	28	(1,449)	35
Other	90	9	—	—	99
Accounts payable-					
Affiliated companies	1,068	197	219	(1,068)	416
Other	46	202	—	—	248
Accrued taxes	2	62	161	(123)	102
Derivatives	166	—	—	—	166
Other	72	56	9	47	184
	2,597	1,011	765	(2,617)	1,756
CAPITALIZATION:					
Total equity	5,585	2,561	4,014	(6,575)	5,585
Long-term debt and other long-term obligations	695	2,215	859	(1,161)	2,608
	6,280	4,776	4,873	(7,736)	8,193
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	824	824
Accumulated deferred income taxes	13	—	678	(207)	484
Asset retirement obligations	—	189	652	—	841
Retirement benefits	36	288	—	—	324
Derivatives	14	—	—	—	14
Other	33	69	744	1	847
	96	546	2,074	618	3,334
	$ 8,973	$ 6,333	$ 7,712	$ (9,735)	$ 13,283

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2015	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (637)	$ 551	$ 1,261	$ (24)	$ 1,151
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	45	296	—	341
Short-term borrowings, net	796	67	—	(863)	—
Redemptions and Repayments-					
Long-term debt	(17)	(70)	(348)	24	(411)
Short-term borrowings, net	—	—	(28)	(98)	(126)
Common stock dividend payment	(70)	—	—	—	(70)
Other	—	(5)	(1)	—	(6)
Net cash provided from (used for) financing activities	709	37	(81)	(937)	(272)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(223)	(399)	—	(627)
Nuclear fuel	—	—	(190)	—	(190)
Proceeds from asset sales	10	3	—	—	13
Sales of investment securities held in trusts	—	—	733	—	733
Purchases of investment securities held in trusts	—	—	(791)	—	(791)
Cash Investments	(10)	—	—	—	(10)
Loans to affiliated companies, net	(67)	(372)	(533)	961	(11)
Other	—	4	—	—	4
Net cash used for investing activities	(72)	(588)	(1,180)	961	(879)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (600)	$ 408	$ 785	$ (22)	$ 571
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	431	447	—	878
Short-term borrowings, net	247	114	—	(361)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	(1)	(269)	(568)	22	(816)
Short-term borrowings, net	—	—	(123)	(178)	(301)
Other	(1)	(12)	(2)	—	(15)
Net cash provided from (used for) financing activities	745	264	(246)	(517)	246
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8)	(169)	(662)	—	(839)
Nuclear fuel	—	—	(233)	—	(233)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	1,163	—	1,163
Purchases of investment securities held in trusts	—	—	(1,219)	—	(1,219)
Loans to affiliated companies, net	(136)	(815)	412	539	—
Other	(1)	5	—	—	4
Net cash used for investing activities	(145)	(672)	(539)	539	(817)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (1,429)	$ 753	$ 776	$ (22)	$ 78
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	864	371	150	(954)	431
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(364)	(90)	22	(1,202)
Short-term borrowings, net	(244)	(505)	—	749	—
Tender premiums	(67)	—	—	—	(67)
Other	(4)	(5)	—	—	(9)
Net cash provided from (used for) financing activities	1,279	(503)	60	(183)	653
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(12)	(256)	(449)	—	(717)
Nuclear fuel	—	—	(250)	—	(250)
Proceeds from asset sales	—	21	—	—	21
Sales of investment securities held in trusts	—	—	940	—	940
Purchases of investment securities held in trusts	—	—	(1,000)	—	(1,000)
Loans to affiliated companies, net	163	(15)	(77)	205	276
Other	(1)	(1)	—	—	(2)
Net cash provided from (used for) investing activities	150	(251)	(836)	205	(732)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

18. SEGMENT INFORMATION

FirstEnergy's reportable segments are as follows: Regulated Distribution, Regulated Transmission and CES.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

During the fourth quarter of 2015, management concluded that FEV's 33-1/3% equity investment in Global Holding was no longer a strategic asset to CES. Because of this decision, the segment reporting was modified to reflect how management now views and makes investment decisions regarding CES and Global Holding. The external segment reporting is consistent with the internal financial reports used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess performance of the business and allocate resources. Disclosures for FirstEnergy's reportable operating segments for 2014 and 2013 have been reclassified to conform to the current presentation reflecting the activity of FEV's investment in Global Holding in Corporate/Other.

The **Regulated Distribution** segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 3,790 MWs of generation capacity.

The **Regulated Transmission** segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are primarily from transmission services provided pursuant to its PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The **CES** segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity. The CES segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs and capacity costs charged by PJM to deliver energy to the segment's customers.

Corporate support and other businesses that do not constitute an operating segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates and $1.7 billion was borrowed under the FE revolving credit facility.

Segment Financial Information

For the Years Ended December 31,	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate / Other	Reconciling Adjustments	Consolidated
			(In millions)			
2015						
External revenues	$ 9,625	$ 1,011	$ 4,698	$ (168)	$ (140)	$ 15,026
Internal revenues	—	—	686	—	(686)	—
Total revenues	9,625	1,011	5,384	(168)	(826)	15,026
Depreciation	672	156	394	60	—	1,282
Amortization of regulatory assets, net	261	7	—	—	—	268
Impairment of long-lived assets	8	—	34	—	—	42
Investment income (loss)	42	—	(16)	(9)	(39)	(22)
Impairment of equity method investment	—	—	—	362	—	362
Interest expense	586	161	192	193	—	1,132
Income taxes (benefits)	342	174	50	(262)	11	315
Income (loss) from continuing operations	618	298	89	(427)	—	578
Discontinued operations, net of tax	—	—	—	—	—	—
Net income (loss)	618	298	89	(427)	—	578
Total assets	27,876	7,439	16,365	507	—	52,187
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,108	952	588	56	—	2,704
2014						
External revenues	$ 9,102	$ 769	$ 5,470	$ (146)	$ (146)	$ 15,049
Internal revenues	—	—	819	—	(819)	—
Total revenues	9,102	769	6,289	(146)	(965)	15,049
Depreciation	658	127	387	48	—	1,220
Amortization of regulatory assets, net	1	11	—	—	—	12
Impairment of long-lived assets	—	—	—	—	—	—
Investment income (loss)	56	—	54	2	(40)	72
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	589	131	189	168	(4)	1,073
Income taxes (benefits)	227	121	(223)	(178)	11	(42)
Income (loss) from continuing operations	465	223	(417)	(58)	—	213
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	465	223	(331)	(58)	—	299
Total assets	28,085	6,252	16,518	793	—	51,648
Total goodwill	5,092	526	800	—	—	6,418
Property additions	972	1,329	939	72	—	3,312
2013						
External revenues	$ 8,720	$ 731	$ 5,728	$ (121)	$ (166)	$ 14,892
Internal revenues	—	—	770	—	(770)	—
Total revenues	8,720	731	6,498	(121)	(936)	14,892
Depreciation	606	114	439	43	—	1,202
Amortization of regulatory assets, net	529	10	—	—	—	539
Impairment of long-lived assets	322	—	473	—	—	795
Investment income (loss)	57	—	14	6	(44)	33
Impairment of equity method investment	—	—	—	—	—	—
Interest expense	543	93	222	148	10	1,016
Income taxes (benefits)	301	129	(140)	(105)	10	195
Income (loss) from continuing operations	501	214	(235)	(105)	—	375
Discontinued operations, net of tax	—	—	17	—	—	17
Net income (loss)	501	214	(218)	(105)	—	392
Total assets	27,683	5,247	16,782	712	—	50,424
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,272	461	827	78	—	2,638

19. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million). Pre-tax income for the hydroelectric facilities of $155 million and $26 million (FES - $186 million and $22 million) for the years ended December 31, 2014 and 2013, respectively, was included in discontinued operations in the Consolidated Statement of Income. Included in income for discontinued operations in the year ended December 31, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million and $33 million (FES - $5 million and $31 million) for years ended December 31, 2014 and 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income.

20. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2015 and 2014.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME *(In millions, except per share amounts)*	**2015**				**2014**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 3,541	$ 4,123	$ 3,465	$ 3,897	$ 3,483	$ 3,888	$ 3,496	$ 4,182
Other operating expense	952	850	916	1,057	901	858	1,021	1,182
Pension and OPEB mark-to-market adjustment	242	—	—	—	835	—	—	—
Provision for depreciation	313	328	322	319	316	308	302	294
Operating Income (Loss)	236	908	554	594	(337)	716	292	391
Income (loss) from continuing operations before income taxes (benefits)	(396)	621	302	366	(574)	485	90	170
Income taxes (benefits) (1)	(170)	226	115	144	(268)	152	26	48
Income (loss) from continuing operations	(226)	395	187	222	(306)	333	64	122
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	86
Net Income (Loss)	(226)	395	187	222	(306)	333	64	208
Earnings (loss) per share of common stock-(2)								
Basic - Continuing Operations	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.29
Basic - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.21
Basic - Earnings Available to FirstEnergy Corp.	(0.53)	0.94	0.44	0.53	(0.73)	0.79	0.16	0.50
Diluted - Continuing Operations	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.29
Diluted - Discontinued Operations (Note 19)	—	—	—	—	—	—	—	0.20
Diluted - Earnings Available to FirstEnergy Corp.	(0.53)	0.93	0.44	0.53	(0.73)	0.79	0.15	0.49

(1) During the fourth quarter of 2014, income tax benefits of $16 million were recorded that related to prior periods. The out-of-period adjustment primarily related to the correction of amounts included in the Company's tax basis balance sheet. Management determined that this adjustment was not material to 2014 or any prior period.

(2) Total quarterly earnings per share information may not equal annual earnings per share due to the issuance of shares throughout the year. See FirstEnergy's Consolidated Statements of Stockholders' Equity and Note 4. Stock-Based Compensation for additional information.

FES

CONSOLIDATED STATEMENTS OF INCOME *(In millions)*	**2015**				**2014**			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	$ 1,171	$ 1,338	$ 1,119	$ 1,377	$ 1,342	$ 1,521	$ 1,452	$ 1,829
Other operating expense	329	246	353	413	359	356	468	452
Pension and OPEB mark-to-market adjustment	57	—	—	—	297	—	—	—
Provision for depreciation	84	79	81	80	83	83	79	74
Operating Income (Loss)	25	240	—	12	(321)	90	(151)	(148)
Income (loss) from continuing operations before income taxes (benefits)	(13)	190	(25)	(5)	(347)	72	(154)	(159)
Income taxes (benefits)	1	70	(4)	(2)	(133)	28	(67)	(56)
Income (loss) from continuing operations	(14)	120	(21)	(3)	(214)	44	(87)	(103)
Discontinued operations (net of income taxes)	—	—	—	—	—	—	—	116
Net Income (Loss)	(14)	120	(21)	(3)	(214)	44	(87)	13

Executive Officers as of February 16, 2016

Name	Age	Positions Held During Past Five Years	Dates
G. D. Benz	56	Senior Vice President, Strategy (B)	2015-present
		Vice President, Supply Chain (B)	2012-2015
L. M. Cavalier	64	Chief Human Resources Officer (B)	2015-present
		Senior Vice President, Human Resources (B)	*-2015
D. M. Chack	65	Senior Vice President, Marketing and Branding (B)	2015-present
		President, Ohio Operations (B)	2011-2015
		Vice President (C)	2011-2015
		Regional President (M)	*-2011
M. J. Dowling	51	Senior Vice President, External Affairs (B)	2011-present
		Vice President, External Affairs (B)	*-2011
B. L. Gaines	62	Senior Vice President, Corporate Services and Chief Information Officer (B)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	*-2011
C. E. Jones	60	President and Chief Executive Officer (A)(B)	2015-present
		Chief Executive Officer (F)	2015-present
		Executive Vice President & President, FirstEnergy Utilities (A)(B)	2014
		Senior Vice President & President, FirstEnergy Utilities (B)	*-2013
		President (H)(I)	2011-2015
		President (C)(D)(L)	*-2015
		Senior Vice President & President, FirstEnergy Utilities (A)	*-2011
J. H. Lash	65	Executive Vice President & President, FE Generation (A)(B)	2015-present
		President, FE Generation (B)	2011-2015
		President (G)(J)	2011-present
		Chief Nuclear Officer (F)	2011-2012
		President and Chief Nuclear Officer (F)	*-2011
		President, FirstEnergy Nuclear Operating Company (B)	*-2011
C. D. Lasky	53	Senior Vice President, Human Resources (B)	2015-present
		Vice President, Fossil Operations (J)	2014-2015
		Vice President, Fossil Operations & Engineering (J)	2014
		Vice President (G)	2011-2015
		Vice President, Fossil Fleet Operations (J)	2011-2013
		Vice President (J)	*-2011
		Vice President, Fossil Operations (E)	*-2011
J. F. Pearson	61	Executive Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2015-present
		Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-2015
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(J)(L)	*-2012
		Vice President and Treasurer (G)(H)(I)	2011-2012
D. R. Schneider	54	President (E)	*-present
S. E. Strah	52	Senior Vice President & President, FirstEnergy Utilities (B)	2015-present
		President (C)(D)(H)(I)(L)	2015-present
		Vice President, Distribution Support (B)	2011-2015
		Regional President (K)	*-2011
K. J. Taylor	42	Vice President, Controller and Chief Accounting Officer (A)(B)	2013-present
		Vice President and Controller (C)(D)(E)(F)(G)(H)(I)(J)(L)	2013-present
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2012-2013
		Assistant Controller (A)(B)(C)(D)(L)	*-2012
		Assistant Controller (H)(I)	2011-2012
		Assistant Controller (E)(F)(G)(J)	2012
L. L. Vespoli	56	Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(L)	2014-present
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(J)(L)	*-2013
		Executive Vice President and General Counsel (G)(H)(I)	2011-2013

* Indicates position held at least since January 1, 2011
(A) Denotes executive officer of FE
(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN and Penn
(E) Denotes executive officer of FES
(F) Denotes executive officer of FENOC
(G) Denotes executive officer of AGC
(H) Denotes executive officer of MP, PE and WP
(I) Denotes executive officer of TrAIL and FET
(J) Denotes executive officer of FG
(K) Denotes executive officer of OE
(L) Denotes executive officer of ATSI
(M) Denotes executive officer of CEI

SHAREHOLDER SERVICES

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company, LLC (AST) is the company's Transfer Agent and Registrar. Registered shareholders wanting to transfer stock, or who need assistance or information, can send their stock certificate(s) or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P.O. Box 2016, New York, NY 10272-2016. Shareholders also can call toll-free at 1-800-736-3402, between 8:00 a.m. and 8:00 p.m. Eastern time, Monday through Friday. For Internet access to general shareholder and account information, visit the AST website at www.amstock.com/company/firstenergy.asp.

STOCK INVESTMENT PLAN

Registered shareholders and employees of the company can participate in the Stock Investment Plan. To learn more about the company's Stock Investment Plan, visit AST's website at www.amstock.com/company/firstenergy.asp or contact AST toll-free at 1-800-736-3402.

DIRECT DIVIDEND DEPOSIT

Registered shareholders can have their dividend payments automatically deposited to checking, savings or credit union accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST toll-free at 1-800-736-3402 to receive a Direct Dividend Deposit Authorization Agreement.

STOCK LISTING AND TRADING

The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

FORM 10-K ANNUAL REPORT

The Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, including the financial statements and financial statement schedules, will be sent to you without charge upon written request to Rhonda S. Ferguson, Vice President and Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You also can view the Form 10-K by visiting the company's website at www.firstenergycorp.com/financialreports.

PRESORTED STD
U.S. POSTAGE
PAID
AKRON, OH
PERMIT No. 561

76 South Main Street, Akron, Ohio 44308-1890

FirstEnergy®

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-2:

> "Supply projected capital requirements and sources of the filing utility, its parent and system – consolidated - for the test year and each of 3 comparable future years."

RESPONSE:

See Met-Ed Exhibit JD-18 Attachment A for the test year and 2 comparable future years. The information is not available at this time for the twelve months ending 12/31/2020.

ME Exhibit JD-18
Attachment A
Witness J. Dipre

Metropolitan Edison Company
Source and Application of Funds
(in millions)

	Forecast (TME) 12/31/2017	**Forecast** (TME) 12/31/2018	**Forecast** (TME) 12/31/2019
Application of Funds			
Construction	125	123	122
LT/ST Debt Interest	53	58	55
Maturities of Bonds & other Long Term Debt	0	0	300
Pension Contribution	0	28	0
Other	0	0	0
Total Applications	**178**	**209**	**477**
Sources of Funds			
Internal			
Depreciation & Amortization	69	75	77
Deferred Income Taxes	23	29	16
Dividend payments	(50)	(64)	(66)
Working Capital & Other	121	89	135
Total Internal Sources	163	129	162
External			
Bonds & other Long Term Debt	0	200	300
Short-term Debt/(Temp Investments)	15	(120)	15
Total External Sources	15	80	315
Total Sources	**178**	**209**	**477**

* The information is not available at this time for (TME) 12/31/2020

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-3:

> "State what coverage requirements or capital structure ratios are required in the most restrictive of applicable indentures/charter tests and how these measures have been computed."

RESPONSE:

a.) Senior Note Indenture dated July 1, 1999

There are no coverage or capital structure ratio requirements in Metropolitan Edison's Senior Note Indenture. The Indenture does contain limitation on liens and limitations on sale leaseback transactions which are defined in the Indenture.

b.) Amended and Restated Articles of Incorporation

The Board of Directors may adopt an amendment to these Articles of Incorporation determining, in whole or in part, the express terms, within the limits set forth in these Articles of Incorporation or the Pennsylvania Business Corporation Law, of any class of shares before the issuance of any shares of that class, or of one or more series within a class before the issuance of shares of that series; including, without limitation, division of shares into classes or into series within any class or classes, determination of the designation and the number of shares of any class or series, and the determination of the relative voting rights, preferences, limitations, rights to dividends, conversion rights, redemption rights, stated value, and other special rights of the shares of any class or series.

No Preferred Stock is currently outstanding.

c.) Credit Agreement, dated June 11, 2011, as amended on May 8, 2012, May 8, 2013, October 31, 2013 and March 31, 2014 among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company as borrowers.

Metropolitan Edison is a borrower under the Credit Agreement and must maintain a Debt to Capitalization Ratio of no more than 0.65 to 1.00 (determined as of the last day of each fiscal quarter). The calculation is defined in the Credit Agreement. The relevant definitions are shown in Met-Ed Exhibit JD-19, Attachment A.

"***Debt to Capitalization Ratio***" means, for any Borrower, the ratio of Consolidated Debt of such Borrower to Total Capitalization of such Borrower.

"***Consolidated Debt***" means, with respect to any Borrower at any date of determination the aggregate Indebtedness of such Borrower and its Consolidated Subsidiaries determined on a consolidated basis in accordance with GAAP, but shall not include (i) Nonrecourse Indebtedness of such Borrower and any of its Subsidiaries, (ii) obligations under leases that shall have been or should be, in accordance with GAAP, recorded as operating leases in respect of which such Borrower or any of its Consolidated Subsidiaries is liable as a lessee, (iii) the aggregate principal and/or face amount of Attributable Securitization Obligations of such Borrower and its Consolidated Subsidiaries and (iv) the aggregate principal amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Obligations not exceeding 15% of the Total Capitalization of such Borrower and its Consolidated Subsidiaries (determined, for purposes of such calculation, without regard to the amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Debt Obligations outstanding of such Borrower); *provided* that the amount of any mandatory principal amortization or defeasance of Trust Preferred Securities or Junior Subordinated Deferred Interest Debt Obligations prior to the Termination Date shall be included in this definition of Consolidated Debt.

"***Indebtedness***" of any Person means at any date, without duplication, (i) all obligations of such Person for borrowed money, or with respect to deposits or advances of any kind, or for the deferred purchase price of property or services other than trade accounts payable, (ii) all obligations of such Person evidenced by bonds, debentures, notes or similar instruments, (iii) all obligations of such Person upon which interest charges are customarily paid, (iv) all obligations under leases that shall have been or should be, in accordance with GAAP, recorded as capital leases in respect of which such Person is liable as lessee, (v) withdrawal liability incurred under ERISA by such Person or any of its affiliates to any Multiemployer Plan, (vi) reimbursement obligations of such Person (whether contingent or otherwise) in respect of letters of credit, bankers acceptances, surety or other bonds and similar instruments, (vii) all Indebtedness of others secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person and (viii) obligations of such Person under direct or indirect guaranties in respect of, and obligations (contingent or otherwise) to purchase or otherwise acquire, or otherwise to assure a creditor against loss in respect of, indebtedness or obligations of others of the kinds referred to above.

"***Nonrecourse Indebtedness***" means, with respect to any Borrower and its Subsidiaries, (i) any Indebtedness that finances the acquisition, development, construction or improvement of an asset in respect of which the Person to which such Indebtedness is owed has no recourse whatsoever to such Borrower or any of its

Affiliates and (ii) any Indebtedness existing on the date of this Agreement that finances the ownership or operation of an asset in respect of which the Person to which such Indebtedness is owed has no recourse whatsoever to such Borrower or any of its Affiliates, in each case of clauses (i) and (ii), other than:

(A) recourse to the named obligor with respect to such Indebtedness (the "***Debtor***") for amounts limited to the cash flow or net cash flow (other than historic cash flow) from the asset; and

(B) recourse to the Debtor for the purpose only of enabling amounts to be claimed in respect of such Indebtedness in an enforcement of any security interest or lien given by the Debtor over the asset or the income, cash flow or other proceeds deriving from the asset (or given by any shareholder or the like in the Debtor over its shares or like interest in the capital of the Debtor) to secure the Indebtedness, but only if the extent of the recourse to the Debtor is limited solely to the amount of any recoveries made on any such enforcement; and

(C) recourse to the Debtor generally or indirectly to any Affiliate of the Debtor, under any form of assurance, undertaking or support, which recourse is limited to a claim for damages (other than liquidated damages and damages required to be calculated in a specified way) for a breach of an obligation (other than a payment obligation or an obligation to comply or to procure compliance by another with any financial ratios or other tests of financial condition) by the Person against which such recourse is available.

"***Total Capitalization***" means, with respect to any Borrower at any date of determination the sum, without duplication, of (i) Consolidated Debt of such Borrower, (ii) the capital stock (but excluding treasury stock and capital stock subscribed and unissued) and other equity accounts (including retained earnings and paid in capital but excluding accumulated other comprehensive income and loss) of such Borrower and its Consolidated Subsidiaries, (iii) consolidated equity of the preference stockholders of such Borrower and its Consolidated Subsidiaries, and (iv) the aggregate principal amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Debt Obligations of such Borrower and its Consolidated Subsidiaries; *provided*, *however*, that, commencing with the fiscal quarter ended September 30, 2013 and for each fiscal quarter ending thereafter, '***Total Capitalization***' shall be determined subject to the following adjustments:

(A) as applicable, for the respective Borrowers, there shall be excluded in such determination the following after-tax effects resulting from non-cash write-downs and non-cash charges occurring and recognized for the periods indicated below as reflected in the consolidated financial statements of the applicable Borrowers for such periods:

(1) in respect of pension and other postemployment benefits occurring and recognized in fiscal years 2011 and 2012, which shall not exceed in the aggregate $691,600,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation);

(2) in respect of asset impairments attributable to the Albright, Rivesville and Willow Island Plants owned by MP, the Armstrong and R. Paul Plants owned by AESC, and the Bay Shore (Units 2-4 only), Eastlake (Units 4-5 only), Fremont and Richland Plants owned by FirstEnergy Generation, LLC occurring and recognized in fiscal year 2011, which shall not exceed in the aggregate $255,400,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation); and

(3) in respect of asset impairments attributable to the Hatfield's Ferry Power Station and the Mitchell Power Station owned by AESC occurring and recognized in fiscal year 2013 through September 30, 2013, which shall not exceed in the aggregate $317,300,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation); and

(B) in addition to the adjustments described in clause (A) above, for the respective Borrowers there shall be excluded in such determination the after-tax effects resulting from non-cash write-downs and non-cash charges attributable or relating to the following: (1)(i) pension and other postemployment benefits, (ii) impairment of regulatory and other long-lived assets, (iii) disallowance of regulatory assets, and (iv) goodwill impairment, in each case, occurring and recognized during the fiscal quarter ending December 31, 2013 and in any fiscal quarter ending thereafter as reflected in the consolidated financial statements of the respective Borrowers for such periods, and (2) disallowance of regulatory assets consisting of marginal transmission line losses of Met-Ed and Penelec occurring during the period from January 11, 2007 through December 31, 2010 as described in the PPUC Order, in each case, occurring and recognized during the fiscal quarter ended September 30, 2013 as reflected in the consolidated financial statements of the respective Borrowers for such period, but such adjustments shall not exceed in the aggregate $1,500,000,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation).

"***Trust Preferred Securities***" means any securities, however denominated, (i) issued by any Borrower or any Consolidated Subsidiary of any Borrower, (ii) that are not subject to mandatory redemption or the underlying securities, if any, of which are not subject to mandatory redemption, (iii) that are perpetual or mature no less than 30 years from the date of issuance, (iv) the indebtedness issued in connection with which, including any guaranty, is subordinate in right of payment to the unsecured and unsubordinated indebtedness of the issuer of such indebtedness or guaranty, and

(v) the terms of which permit the deferral of the payment of interest or distributions thereon to a date occurring after the Termination Date.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-4:

"A schedule of comparative financial data shall be supplied for the test year, the most immediately available annual historical period, prior to the test year, and the 2 calendar years most immediately preceding the test year. Changes in Moody's/S&P ratings, noted on this schedule, shall be accompanied by the Moody's/S&P write up of such change, if available. The following financial data and ratios shall be supplied for the utility's parent, where applicable, if not available for the utility.

a. Times interest earned ratio – pre-tax and post-tax basis
b. Preferred stock dividend coverage ratio—post-tax basis.
c. Times fixed charges earned ratio—pre-tax basis.
d. Earnings per share.
e. Dividend per share.
f. Average dividend yield (52-week high/low common stock price).
g. Average book value per share.
h. Average market price per share.
i. Market price-book value ratio.
j. Earnings-book value ratio (per share basis, average book value).
k. Dividend payout ratio.
l. AFUDC as a % of earnings available for common equity.
m. Construction work in progress as a % of net utility plant.
n. Effective income tax rate.
o. Internal cash generations as a % of total capital requirements."

RESPONSE:

See ME Exhibit JD-20 Attachments A and B.

ME Exhibit JD-20
Attachment A
Witness: J. Dipre

Metropolitan Edison / FirstEnergy Corporation
Comparative Financial Data

	Times Interest Earned Ratio X	Preferred Stock Coverage Post-tax[1] X	Fixed Charges Earned X	Basic Earnings Per Share $	Dividends Per Share $	Average Dividend Yield %	Average Book Value $	Average Market Price $	Market To Book %	Earnings To Book %	Dividend Payout %	AFUDC as % of Earnings %	CWIP as % of Net Utility Plant %	Effective Income Tax Rate %	Internal Cash % of Total Cap. Rqts. %
Actual															
12/31/2014 - MET-ED	2.43		2.36									3.0%	4.4%	36.8%	124%
12/31/2015 - MET-ED	3.41		3.32									1.8%	3.5%	42.1%	149%
2015 Annual - FE				$1.37	$ 1.44	4.07%	$ 29.51	$ 35.36	120%	4.65%	105%				121%
Forecast															
12/31/2016 -MET-ED	3.73		3.63									0.7%	0.9%	41.4%	120%
12/31/2017 -MET-ED	3.13		3.10									0.5%	1.1%	41.4%	127%

[1] FE Corp. and Met-Ed do not have Preferred Stock Dividend Requirements

On July 15, 2014, Moody's made the following ratings actions on PA utilities:

- Upgraded Met-Ed's senior unsecured and issuer rating to Baa1 from Baa2.
- Upgraded Penn Power's issuer rating to Baa1 from Baa2; senior secured to A2 from A3.
- Upgraded West Penn Power's issuer rating to Baa1 from Baa2; senior secured to A2 from A3.
- Affirmed Penelec's Baa2 senior unsecured and issuer rating

Moody's Investor Services		12/31/2015	7/15/2014	12/31/2013	12/31/2012
Metropolitan Edison	Issuer Rating	Baa1	Baa1	Baa2	Baa2
	Senior Secured	-	-	-	-
	Senior Unsecured	Baa1	Baa1	Baa2	Baa2
	Outlook	stable	stable	stable	stable
Pennsylvania Electric Co.	Issuer Rating	Baa2	Baa2	Baa2	Baa2
	Senior Secured	-	-	-	-
	Senior Unsecured	Baa2	Baa2	Baa2	Baa2
	Outlook	stable	stable	stable	stable
Pennsylvania Power Co.	Issuer Rating	Baa1	Baa1	Baa2	Baa2
	Senior Secured	A2	A2	A3	A3
	Senior Unsecured	-	-	-	-
	Outlook	stable	stable	stable	stable
West Penn Power Co.	Issuer Rating	Baa1	Baa1	Baa2	Baa2
	Senior Secured	A2	A2	A3	A3
	Senior Unsecured	-	-	-	-
	Outlook	stable	stable	stable	stable

Standard & Poor's		12/31/2015	7/15/2014	12/31/2013	12/31/2012
Metropolitan Edison	Issuer Rating	BBB-	BBB-	BBB-	BBB-
	Senior Secured	-	-	-	-
	Senior Unsecured	BBB-	BBB-	BBB-	BBB-
	Outlook	stable	stable	stable	stable
Pennsylvania Electric Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-
	Senior Secured	-	-	-	-
	Senior Unsecured	BBB-	BBB-	BBB-	BBB-
	Outlook	stable	stable	stable	stable
Pennsylvania Power Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-
	Senior Secured	BBB+	BBB+	BBB+	BBB+
	Senior Unsecured	-	-	-	-
	Outlook	stable	stable	stable	stable
West Penn Power Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-
	Senior Secured	BBB+	BBB+	BBB+	BBB+
	Senior Unsecured	-	-	-	-
	Outlook	stable	stable	stable	stable

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-1:

"Provide a complete support for claimed common equity rate of return."

RESPONSE:

See the direct testimony and exhibits of Joseph Dipre (Met-Ed Statement No. 9) and Pauline Ahern (Met-Ed Statement No. 8).

Metropolitan Edison Company
Capitalization & Capitalization Ratios
($000)

	Actuals at December 31, 2015		Forecast at December 31, 2016		Forecast at December 31, 2017	
	Amount Outstanding	Ratios Rate Making	Amount Outstanding	Ratios Rate Making	Amount Outstanding	Ratios Rate Making
Long Term Debt [1]	849,104	51.6%	849,210 [2]	49.5%	849,316 [2]	48.8%
Preferred Stock	0	0.0%	0	0.0%	0	0.0%
Common Equity	797,349	48.4%	867,833	50.5%	889,984	51.2%
Total Capital	1,646,453	100.0%	1,717,043	100.0%	1,739,300	100.0%

Notes:
(1) Includes current portion of long-term debt
(2) Reflects changes in long-term debt of:

	2016	2017
Unamort discount on long-term debt	106	106

Metropolitan Edison Company
Schedule of Long Term Debt Outstanding at 12/31/2017

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(3,006,738)	296,993,262		3.6204%	
4.00% Series	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,758,140)	247,241,860		4.1258%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(2,372,217)	297,627,783		7.8154%	
			850,000,000	**850,000,000**	-				**(8,137,095)**	**841,862,905**			**5.2496%**

Met-Ed
Capital Cost Rates
12/31/2017

	($000)	Ratios	Cost Rate	Weighted Average Cost of Capital
Common Equity	889,984	51.17%	10.90%	5.58%
Preferred Stock	-			
Long-term Debt	849,316	48.83%	5.2496%	2.56%
Total Capitalization	1,739,300	100.00%		8.14%