FIRSTENERGY CORP
Form 10-Q
August 06, 2013

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

FORM 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2013

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________________ to ____________________

Commission File 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

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 þ No o FirstEnergy Corp. and FirstEnergy Solutions Corp.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 þ No o FirstEnergy Corp. and 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 þ FirstEnergy Corp.

Accelerated Filer o	N/A
Non-accelerated Filer (Do not check if a smaller reporting company) þ	FirstEnergy Solutions Corp.
Smaller Reporting Company o	N/A

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes o No þ FirstEnergy Corp. and FirstEnergy Solutions Corp.
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 AUGUST 5, 2013
FirstEnergy Corp., $0.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.
This combined Form 10-Q is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. Information contained herein relating to any 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.
FirstEnergy Web Site 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 web site at www.firstenergycorp.com.
These SEC filings are posted on the web site 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 web site and recognize FirstEnergy’s Internet web site 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 SEC Regulation FD. Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet web site 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 an additional channel of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy’s Internet web site or its Twitter or Facebook site, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report.
OMISSION OF CERTAIN INFORMATION
FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

Forward-Looking Statements: This Form 10-Q 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,” “believe,” “estimate” 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.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases.
- 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.
- Regulatory outcomes associated with storms, including but not limited to Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- 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 possible GHG emission, water discharge, water intake and coal combustion residual regulations, the potential impacts of CSAPR, CAIR, and/or any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- 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 expenditures 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 decision to deactivate the Hatfield's Ferry and Mitchell Power Stations, the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and the reliability of the transmission grid.
- 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).
- Adverse legal decisions and outcomes related to ME's and PN's ability to recover certain transmission costs through their TSC riders.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or inadequately 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 reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, proposed capital raising and debt reduction initiatives, the proposed West Virginia asset transfer and potential sale of non-core hydro assets.

- 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.
- The ability to experience growth in the Regulated Distribution segment and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- Changing market conditions that could affect the measurement of liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and 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 announced financial plan, 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 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 our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.

- 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.

The foregoing review of factors 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.

TABLE OF CONTENTS

i

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
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
Allegheny Utilities	MP, PE and WP
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
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, a subsidiary of AE, 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 subsidiary of FES, which owns and operates non-nuclear generating facilities
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	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE
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 Allegheny 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 electric utility operating subsidiary of AE
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	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 of AE

The following abbreviations and acronyms are used to identify frequently used terms in this report:

AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right

GLOSSARY OF TERMS, Continued

ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BTU	British Thermal Units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EIS	Environmental Impact Statement
ELPC	Environmental Law & Policy Center
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
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
ICC	Illinois Commerce Commission
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
ILP	Integrated License Application Process
kV	Kilovolt
KWH	Kilowatt-hour
LAR	License Amendment Request
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LITE	Local Infrastructure and Transmission Enhancement
LOC	Letter of Credit

LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.

GLOSSARY OF TERMS, Continued

mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
NYSEG	New York State Electric and Gas
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
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 LLC
PI	Performance Indicator
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
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
SAMA	Severe Accident Mitigation Alternatives

GLOSSARY OF TERMS, Continued

SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
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
TSC	Transmission Service Charge
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions, except per share amounts)	2013	2012	2013	2012
REVENUES:				
Electric utilities	$2,221	$2,323	$4,609	$4,863
Unregulated businesses	1,298	1,432	2,639	2,882
Total revenues*	3,519	3,755	7,248	7,745
OPERATING EXPENSES:				
Fuel	628	656	1,258	1,197
Purchased power	862	1,042	1,805	2,301
Other operating expenses	887	921	1,771	1,739
Provision for depreciation	302	285	596	564
Amortization of regulatory assets, net	72	62	131	137
General taxes	241	232	506	504
Impairment of long-lived assets	473	—	473	—
Total operating expenses	3,465	3,198	6,540	6,442
OPERATING INCOME	54	557	708	1,303
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	(24)	—	(141)	—
Investment income (loss)	(15)	13	3	24
Interest expense	(256)	(274)	(514)	(520)
Capitalized interest	19	19	34	36
Total other expense	(276)	(242)	(618)	(460)
INCOME (LOSS) BEFORE INCOME TAXES	(222)	315	90	843
INCOME TAXES (BENEFITS)	(58)	127	58	349
NET INCOME (LOSS)	(164)	188	32	494
Income attributable to noncontrolling interest	—	1	—	1
EARNINGS (LOSSES) AVAILABLE TO FIRSTENERGY CORP.	$(164)	$187	$32	$493
EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:				
Basic	$(0.39)	$0.45	$0.08	$1.18

Diluted	$(0.39)	$0.45	$0.08	$1.18
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	418	417	418	418
Diluted	418	419	419	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$—	$—	$0.55	$0.55

* Includes excise tax collections of $107 million in each of the three month periods ended June 30, 2013 and 2012 and $229 million and $228 million in the six months ended June 30, 2013 and 2012, respectively.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

1

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2013	2012	2013	2012
NET INCOME (LOSS)	$(164)	$188	$32	$494
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(55)	(48)	(101)	(101)
Amortized losses on derivative hedges	1	3	2	1
Change in unrealized gain on available-for-sale securities	(8)	2	(3)	12
Other comprehensive loss	(62)	(43)	(102)	(88)
Income tax benefits on other comprehensive loss	(24)	(27)	(40)	(51)
Other comprehensive loss, net of tax	(38)	(16)	(62)	(37)
COMPREHENSIVE INCOME (LOSS)	(202)	172	(30)	457
Comprehensive income attributable to noncontrolling interest	—	1	—	1
COMPREHENSIVE INCOME (LOSS) AVAILABLE TO FIRSTENERGY CORP.	$(202)	$171	$(30)	$456

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$71	$172
Receivables-		
Customers, net of allowance for uncollectible accounts of $40 in 2013 and 2012	1,646	1,614
Other, net of allowance for uncollectible accounts of $3 in 2013 and $4 in 2012	277	315
Materials and supplies, at average cost	806	861
Prepaid taxes	288	119
Derivatives	173	160
Accumulated deferred income taxes	51	319
Other	248	208
	3,560	3,768
PROPERTY, PLANT AND EQUIPMENT:		
In service	43,888	43,210
Less — Accumulated provision for depreciation	13,027	12,600
	30,861	30,610
Construction work in progress	2,230	2,293
	33,091	32,903
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,178	2,204
Investments in lease obligation bonds	46	54
Other	876	936
	3,100	3,194
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,447	6,447
Regulatory assets	2,321	2,375
Other	1,638	1,719
	10,406	10,541
	$50,157	$50,406
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,952	$1,999
Short-term borrowings	3,254	1,969
Accounts payable	950	1,599
Accrued taxes	338	543
Accrued compensation and benefits	298	331
Derivatives	142	126
Other	599	1,038
	7,533	7,605
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 418,216,437 shares outstanding	42	42

Other paid-in capital	9,744	9,769
Accumulated other comprehensive income	323	385
Retained earnings	2,690	2,888
Total common stockholders’ equity	12,799	13,084
Noncontrolling interest	4	9
Total equity	12,803	13,093
Long-term debt and other long-term obligations	15,449	15,179
	28,252	28,272
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,427	6,616
Retirement benefits	3,088	3,080
Asset retirement obligations	1,795	1,599
Deferred gain on sale and leaseback transaction	875	892
Adverse power contract liability	484	506
Other	1,703	1,836
	14,372	14,529
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$50,157	$50,406

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

3

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
(In millions)	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$32	$494
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	596	564
Amortization of regulatory assets, net	131	137
Nuclear fuel amortization	98	106
Deferred purchased power and other costs	(39)	(149)
Deferred income taxes and investment tax credits, net	119	423
Impairments of long-lived assets	473	—
Investment impairments	53	7
Deferred rents and lease market valuation liability	(59)	(106)
Stock based compensation	(22)	(18)
Retirement benefits	(104)	(64)
Commodity derivative transactions, net (Note 9)	21	(86)
Pension trust contributions	—	(600)
Cash collateral, net	(42)	22
Loss on debt redemptions	141	—
Make-whole premiums paid on debt redemptions	(61)	—
Decrease (increase) in operating assets-		
Receivables	(125)	(105)
Materials and supplies	42	(109)
Prepayments and other current assets	(185)	(117)
Increase (decrease) in operating liabilities-		
Accounts payable	(329)	(122)
Accrued taxes	(199)	(192)
Accrued interest	2	(5)
Accrued compensation and benefits	(34)	(96)
Other	(16)	78
Net cash provided from operating activities	493	62
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	2,245	182
Short-term borrowings, net	1,285	1,890
Redemptions and Repayments-		
Long-term debt	(1,968)	(746)
Tender premiums paid on debt redemptions	(110)	—
Common stock dividend payments	(460)	(460)
Other	(16)	(35)
Net cash provided from financing activities	976	831
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,412)	(911)

Nuclear fuel	(50)	(90)
Sales of investment securities held in trusts	1,177	382
Purchases of investment securities held in trusts	(1,173)	(420)
Cash investments	(3)	87
Asset removal costs	(111)	(36)
Other	2	(13)
Net cash used for investing activities	(1,570)	(1,001)
Net change in cash and cash equivalents	(101)	(108)
Cash and cash equivalents at beginning of period	172	202
Cash and cash equivalents at end of period	$71	$94

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

4

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
(In millions)	2013	2012	2013	2012
STATEMENTS OF INCOME (LOSS)				
REVENUES:				
Electric sales to non-affiliates	$1,284	$1,322	$2,624	$2,688
Electric sales to affiliates	140	107	296	230
Other	35	27	69	54
Total revenues	1,459	1,456	2,989	2,972
OPERATING EXPENSES:				
Fuel	332	380	632	675
Purchased power from affiliates	137	133	269	250
Purchased power from non-affiliates	524	434	1,029	921
Other operating expenses	388	393	768	688
Provision for depreciation	78	69	154	132
General taxes	34	32	71	69
Total operating expenses	1,493	1,441	2,923	2,735
OPERATING INCOME (LOSS)	(34)	15	66	237
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	(32)	—	(103)	—
Investment income (loss)	(18)	6	(1)	12
Miscellaneous income	6	20	8	24
Interest expense — affiliates	(5)	(2)	(6)	(4)
Interest expense — other	(39)	(48)	(91)	(89)
Capitalized interest	10	9	19	18
Total other expense	(78)	(15)	(174)	(39)
INCOME (LOSS) BEFORE INCOME TAXES	(112)	—	(108)	198
INCOME TAXES (BENEFITS)	(41)	1	(39)	77
NET INCOME (LOSS)	$(71)	$(1)	$(69)	$121
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)				
NET INCOME (LOSS)	$(71)	$(1)	$(69)	$121
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(5)	8	(11)	3
Amortized loss (gain) on derivative hedges	(1)	1	(2)	(4)
Change in unrealized gain on available-for-sale securities	(8)	3	(3)	13

Other comprehensive income (loss)	(14)	12	(16)	12
Income taxes (benefits) on other comprehensive income (loss)	(5)	2	(6)	4
Other comprehensive income (loss), net of tax	(9)	10	(10)	8
COMPREHENSIVE INCOME (LOSS)	$(80)	$9	$(79)	$129

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$3
Receivables-		
Customers, net of allowance for uncollectible accounts of $15 in 2013 and $16 in 2012	541	483
Affiliated companies	435	379
Other, net of allowance for uncollectible accounts of $3 in 2013 and $2 in 2012	122	91
Notes receivable from affiliated companies	120	276
Materials and supplies	454	505
Derivatives	170	158
Prepayments and other	129	87
	1,973	1,982
PROPERTY, PLANT AND EQUIPMENT:		
In service	12,563	11,997
Less — Accumulated provision for depreciation	4,610	4,408
	7,953	7,589
Construction work in progress	1,016	1,141
	8,969	8,730
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,270	1,283
Other	12	12
	1,282	1,295
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	103	110
Goodwill	24	24
Property taxes	36	36
Unamortized sale and leaseback costs	164	119
Derivatives	87	99
Other	239	253
	653	641
	$12,877	$12,648
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$859	$1,102
Short-term borrowings	4	4
Accounts payable-		
Affiliated companies	514	726
Other	256	159
Accrued taxes	40	171
Derivatives	140	124
Other	179	280
	1,992	2,566
CAPITALIZATION:		

Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	3,082	1,573
Accumulated other comprehensive income	62	72
Retained earnings	2,049	2,118
Total common stockholder's equity	5,193	3,763
Long-term debt and other long-term obligations	2,180	3,118
	7,373	6,881
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	875	892
Accumulated deferred income taxes	647	515
Asset retirement obligations	1,138	965
Retirement benefits	250	241
Derivatives	35	37
Other	567	551
	3,512	3,201
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$12,877	$12,648

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

6

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
(In millions)	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (Loss)	$(69)	$121
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	154	132
Nuclear fuel amortization	98	103
Deferred rents and lease market valuation liability	(56)	(103)
Deferred income taxes and investment tax credits, net	141	162
Investment impairments	45	6
Retirement benefits	(3)	1
Pension trust contribution	—	(209)
Commodity derivative transactions, net (note 9)	22	(53)
Cash collateral, net	(3)	17
Loss on debt redemptions	103	—
Make-whole premiums paid on debt redemptions	(31)	—
Decrease (increase) in operating assets-		
Receivables	(156)	—
Materials and supplies	52	(56)
Prepayments and other current assets	(40)	19
Increase (decrease) in operating liabilities-		
Accounts payable	(104)	243
Accrued taxes	(131)	(167)
Accrued compensation and benefits	3	13
Other	(25)	(10)
Net cash provided from operating activities	—	219
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	—	82
Equity contribution from parent	1,500	—
Redemptions and repayments-		
Long-term debt	(1,179)	(140)
Tender premiums paid on debt redemptions	(67)	—
Other	(5)	(6)
Net cash provided from (used for) financing activities	249	(64)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(350)	(213)
Nuclear fuel	(50)	(90)
Proceeds from asset sales	19	17
Sales of investment securities held in trusts	487	109
Purchases of investment securities held in trusts	(515)	(127)
Loans to affiliated companies, net	156	155

Other	3	(6)
Net cash used for investing activities	(250)	(155)
Net change in cash and cash equivalents	(1)	—
Cash and cash equivalents at beginning of period	3	7
Cash and cash equivalents at end of period	$2	$7

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
(Unaudited)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

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.

FE is a diversified energy holding company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FENOC, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP and FET), FES and its principal subsidiaries (FG and NG) and FESC. During the second quarter of 2013, FE completed a $1.5 billion equity contribution to FES.

These interim financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and disclosures normally included in financial statements and notes prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These interim financial statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2012.

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 accompanying interim financial statements are unaudited, but reflect all adjustments, consisting of normal recurring adjustments, that, in the opinion of management, are necessary for a fair presentation of the financial statements. 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. 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. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 7, 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.

New Accounting Pronouncements

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

2. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets, including regulatory 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.

Generating Plant Retirements - 2013

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

Generating Units	MW Capacity	Location
Hatfield's Ferry, Units 1-3	1,710	Masontown, Pennsylvania
Mitchell, Units 2-3	370	Courtney, Pennsylvania

As a result of this decision, in the second quarter of 2013, 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 is included within the results of the Competitive Energy Services Segment.

Approximately 380 plant employees and generation related positions are expected to be affected by these plant deactivations. Eligible employees will receive severance benefits in 2013 that are currently estimated to be approximately $15 million (pre-tax) and were recognized in Other operating expenses in the Consolidated Statements of Income (Loss) in the second quarter of 2013.

Upon termination of operations at Hatfield's Ferry Units 1-3, AE Supply will have the right to redeem $235 million of its outstanding PCRBs at par.

AE Supply has obligations, such as fuel supply, that could be affected by the plant closings and management is currently unable to reasonably estimate potential costs, or a range thereof, that could be incurred.

Generating Plant Retirements - 2012

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. During the three months and six months ended June 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $10 million ($6 million by FES) and $17 million ($10 million by FES), respectively, as a result of the deactivations. These costs are included in Other operating expenses in the Consolidated Statements of Income (Loss).

Cost Savings Initiatives

In addition to deactivating Hatfield's Ferry and Mitchell, FirstEnergy has identified and intends to implement additional cost control opportunities across the organization. These actions include reductions to medical and other employee benefits and other organizational changes, including a reduction in staffing of an additional 250 positions. FirstEnergy did not recognize any costs in the second quarter of 2013 associated with these actions as final plans were not completed. FirstEnergy expects to incur approximately $3 million (pre-tax) of severance related expenses in the third quarter of 2013.

3. 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	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	2013	2012
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	418	417	418	418
Assumed exercise of dilutive stock options and awards[1]	—	2	1	1
Weighted average number of diluted shares outstanding	418	419	419	419
Earnings (Losses) Available to FirstEnergy Corp.	$(164)	$187	$32	$493

Basic earnings (losses) per share of common stock	$(0.39)	$0.45	$0.08	$1.18
Diluted earnings (losses) per share of common stock	$(0.39)	$0.45	$0.08	$1.18

(1) For the three months ended June 30, 2013, 1 million shares were excluded from the calculation of diluted shares outstanding, as a net loss was incurred and the inclusion of any other potential shares outstanding would be antidilutive. The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the three months ended June 30, 2012 and six months ended June 30, 2013 and 2012.

10

4. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

The components of the consolidated net periodic cost for pensions and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended June 30,	2013	2012	2013	2012
	(In millions)			
Service costs	$49	$40	$3	$3
Interest costs	93	97	9	12
Expected return on plan assets	(125)	(121)	(8)	(9)
Amortization of prior service costs (credits)	3	3	(58)	(51)
Net periodic costs (credits)	$20	$19	$(54)	$(45)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Six Months Ended June 30,	2013	2012	2013	2012
	(In millions)			
Service costs	$98	$80	$6	$6
Interest costs	186	194	18	24
Expected return on plan assets	(250)	(242)	(16)	(18)
Amortization of prior service costs (credits)	6	6	(107)	(102)
Net periodic costs (credits)	$40	$38	$(99)	$(90)

Pension and OPEB obligations are allocated to FE's subsidiaries employing the plan participants. The net periodic pension and OPEB costs (net of amounts capitalized) recognized in earnings by FE and FES were as follows:

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Three Months Ended June 30,	2013	2012	2013	2012
	(In millions)			
FirstEnergy	$14	$14	$(34)	$(32)
FES	5	5	(5)	(4)

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Six Months Ended June 30,	2013	2012	2013	2012
	(In millions)			
FirstEnergy	$25	$27	$(64)	$(62)
FES	8	8	(8)	(8)

5. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and six months ended June 30, 2013 and 2012, for FirstEnergy and FES are shown in the following tables:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of April 1, 2013	$(37)	$18	$380	$361
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	—	(4)	(33)	(37)
Net other comprehensive loss	—	(5)	(33)	(38)
AOCI Balance as of June 30, 2013	$(37)	$13	$347	$323
AOCI Balance as of April 1, 2012	$(42)	$25	$422	$405
Other comprehensive income before reclassifications	1	4	—	5
Amounts reclassified from AOCI	2	(2)	(21)	(21)
Net other comprehensive income (loss)	3	2	(21)	(16)
AOCI Balance as of June 30, 2012	$(39)	$27	$401	$389

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of April 1, 2013	$2	$17	$52	$71
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	(1)	(4)	(3)	(8)
Net other comprehensive loss	(1)	(5)	(3)	(9)
AOCI Balance as of June 30, 2013	$1	$12	$49	$62
AOCI Balance as of April 1, 2012	$4	$22	$48	$74
Other comprehensive income before reclassifications	1	4	8	13
Amounts reclassified from AOCI	1	(1)	(3)	(3)
Net other comprehensive income	2	3	5	10
AOCI Balance as of June 30, 2012	$6	$25	$53	$84

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2013	$(38)	$15	$408	$385
Other comprehensive income before reclassifications	—	14	—	14
Amounts reclassified from AOCI	1	(16)	(61)	(76)
Net other comprehensive income (loss)	1	(2)	(61)	(62)
AOCI Balance as of June 30, 2013	$(37)	$13	$347	$323
AOCI Balance as of January 1, 2012	$(39)	$19	$446	$426
Other comprehensive income before reclassifications	1	13	5	19
Amounts reclassified from AOCI	(1)	(5)	(50)	(56)
Net other comprehensive income (loss)	—	8	(45)	(37)
AOCI Balance as of June 30, 2012	$(39)	$27	$401	$389

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2013	$3	$13	$56	$72
Other comprehensive income before reclassifications	—	13	—	13
Amounts reclassified from AOCI	(2)	(14)	(7)	(23)
Net other comprehensive loss	(2)	(1)	(7)	(10)
AOCI Balance as of June 30, 2013	$1	$12	$49	$62
AOCI Balance as of January 1, 2012	$8	$16	$52	$76
Other comprehensive income before reclassifications	1	13	8	22
Amounts reclassified from AOCI	(3)	(4)	(7)	(14)
Net other comprehensive income (loss)	(2)	9	1	8
AOCI Balance as of June 30, 2012	$6	$25	$53	$84

The following amounts were reclassified from AOCI in the three months ended June 30, 2013 and 2012:

FE Reclassifications from AOCI (b)	Three Months Ended June 30 2013	 2012	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(1)	$1	Other operating expenses
Long-term debt	2	2	Interest expense
	1	3	Total before taxes
	1	1	Income taxes (benefits)
	$—	$2	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(6)	$(3)	Investment income
	(2)	(1)	Income taxes (benefits)
	$(4)	$(2)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(55)	$(48)	(a)
	(22)	(27)	Income taxes (benefits)
	$(33)	$(21)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.
(b) Parenthesis represent credits from AOCI

FES Reclassifications from AOCI (b)	Three Months Ended June 30 2013	 2012	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(1)	$1	Other operating expenses
	—	—	Income taxes (benefits)
	$(1)	$1	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(6)	$(2)	Investment income
	(2)	(1)	Income taxes (benefits)
	$(4)	$(1)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(5)	$(5)	(a)
	(2)	(2)	Income taxes (benefits)
	$(3)	$(3)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.
(b) Parenthesis represent credits from AOCI

14

The following amounts were reclassified from AOCI in the six months ended June 30, 2013 and 2012:

FE Reclassifications from AOCI (b)	Six Months Ended June 30 2013	 2012	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(4)	$(5)	Other operating expenses
Long-term debt	6	4	Interest expense
	2	(1)	Total before taxes
	1	—	Income taxes (benefits)
	$1	$(1)	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(25)	$(8)	Investment income
	(9)	(3)	Income taxes (benefits)
	$(16)	$(5)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(101)	$(96)	(a)
	(40)	(46)	Income taxes (benefits)
	$(61)	$(50)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.
(b) Parenthesis represent credits from AOCI

FES Reclassifications from AOCI (b)	Six Months Ended June 30 2013	 2012	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$(4)	$(4)	Other operating expenses
Long-term debt	2	—	Interest expense
	(2)	(4)	Total before taxes
	—	(1)	Income taxes (benefits)
	$(2)	$(3)	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$(22)	$(6)	Investment income
	(8)	(2)	Income taxes (benefits)
	$(14)	$(4)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$(11)	$(10)	(a)
	(4)	(3)	Income taxes (benefits)
	$(7)	$(7)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.

(b) Parenthesis represent credits from AOCI

6. INCOME TAXES

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Significant judgment is required in determining FirstEnergy's income taxes and in evaluating tax positions taken or expected to be taken on its tax returns. There were no material changes to FirstEnergy's unrecognized income tax benefits during the first six months of 2013 or 2012.

As of June 30, 2013, it is reasonably possible that approximately $4 million of unrecognized income tax benefits may be resolved within the next twelve months, all of which, if recognized, would affect FirstEnergy's effective tax rate.

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. During the first six months of 2013 and 2012, there were no material changes to the amount of accrued interest. The net amount of interest accrued as of June 30, 2013 and December 31, 2012 was approximately $9 million.

As of December 31, 2012, the deferred income taxes consisted of $319 million of current federal, $466 million of long-term federal and $389 million of state and local net operating loss carryforwards. The American Taxpayer Relief Act of 2012 (Act) was enacted in January 2013 and provides 50% accelerated (bonus) depreciation for qualifying expenditures made in 2013. As a result of the availability of 50% bonus depreciation for 2013, approximately $268 million of the current federal deferred tax asset as of December 31, 2012, will not be realized in 2013, but will be available for future years and therefore has been reclassified to a long-term federal deferred tax asset as of June 30, 2013. It is not anticipated that FES will realize any of the current federal deferred tax asset in 2013.

As discussed in Note 2, Impairment of Long-Lived Assets, on July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating two coal-fired generating plants. As a result of the decision, FirstEnergy determined that it is more likely than not that certain state and local net operating loss carryforwards will not be realized through future operations or through the reversal of existing temporary differences. As a result, FirstEnergy recorded a valuation reserve of approximately $20 million against net operating loss carryforwards in the second quarter of 2013.

On July 9, 2013, Pennsylvania House Bill 465 (HB 465) was enacted, adopting new market-based sourcing rules for certain items of income as well as increasing the Pennsylvania net operating loss deduction credit for tax years beginning after December 31, 2013 and 2014 to 25% and 30% of taxable income or $4 million and $5 million, respectively. FirstEnergy is evaluating the impact of HB 465, however it currently estimates that net operating loss carryforward valuation reserves will be reduced by approximately $11 million in the third quarter of 2013, as a result of HB 465.

FirstEnergy's three and six months ended June 30, 2013 effective tax rate of 26.1% and 64.4%, respectively, is primarily due to the recognition of valuation reserves of approximately $22 million against net operating loss carryforwards recorded in the second quarter of 2013.

7. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy 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. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy's consolidated financial statements are: the PNBV capital trust that was created to refinance debt originally issued in connection with sale and leaseback transactions; wholly owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities.

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility. In June 2013, the SPEs formed by the Ohio Companies issued $445 million of phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of

5.71% and pay $30 million of make-whole premiums associated with such redemptions which will also be recovered. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

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. The change in noncontrolling interest within the Consolidated Balance Sheets during the six months ended June 30, 2013, was primarily due to $5 million of distributions to owners.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into the following categories based on similar risk characteristics and significance.

Mining Operations

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. 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.

Trusts

FirstEnergy's consolidated financial statements include PNBV. FirstEnergy used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

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 AE 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 the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 11, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities 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 18 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 two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; 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 to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $41 million and $58 million during the three months ended June 30, 2013 and 2012, respectively and $90 million and $118 million during the six months ended June 30, 2013 and 2012, respectively.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangement.

During 2012, NG repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million. In 2012, FG acquired certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million and in March of 2013, FG acquired the remaining interests for approximately $221 million.

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 June 30, 2013:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,268	$1,060	$208
Other FE subsidiaries	828	322	506

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.2 billion.

8. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING 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 process for FTRs, NUGs and LCAPPs 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 9, 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 MWH. 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.

LCAPP contracts are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. LCAPP contracts are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2016/2017 delivery year are developed through a simulation of future PJM RPM auctions. The capacity price forecast assumes a continuation of the current PJM RPM market design and is reflective of the regional peak demand growth and generation fleet additions and retirements that underlie FirstEnergy's long-term energy price forecast. 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 June 30, 2013, from those used as of December 31, 2012. 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 six months ended June 30, 2013. 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	June 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,296	$—	$1,296	$—	$1,259	$—	$1,259
Derivative assets - commodity contracts	1	252	—	253	—	252	—	252
Derivative assets - FTRs	—	—	7	7	—	—	8	8
Derivative assets - NUG contracts[1]	—	—	24	24	—	—	36	36
Equity securities[2]	457	—	—	457	310	—	—	310
Foreign government debt securities	—	108	—	108	—	126	—	126
U.S. government debt securities	—	156	—	156	—	179	—	179
U.S. state debt securities	—	235	—	235	—	299	—	299
Other[3]	91	171	—	262	126	227	—	353
Total assets	$549	$2,218	$31	$2,798	$436	$2,342	$44	$2,822
Liabilities								
Derivative liabilities - commodity contracts	$(9)	$(159)	$—	$(168)	$(3)	$(151)	$—	$(154)
Derivative liabilities - FTRs	—	—	(9)	(9)	—	—	(9)	(9)
Derivative liabilities - NUG contracts[1]	—	—	(256)	(256)	—	—	(290)	(290)
Derivative liabilities - LCAPP contracts[1]	—	—	(158)	(158)	—	—	(144)	(144)
Total liabilities	$(9)	$(159)	$(423)	$(591)	$(3)	$(151)	$(443)	$(597)
Net assets (liabilities)[4]	$540	$2,059	$(392)	$2,207	$433	$2,191	$(399)	$2,225

(1) NUG and LCAPP contracts are generally 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 short-term cash investments.

(4) Excludes $4 million and $110 million as of June 30, 2013 and December 31, 2012, 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 and LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2013 and December 31, 2012:

	NUG Contracts[1]			LCAPP Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)								
January 1, 2012 Balance	$57	$(349)	$(292)	$—	$—	$—	$1	$(23)	$(22)
Unrealized gain (loss)	(20)	(180)	(200)	—	1	1	6	(6)	—
Purchases	—	—	—	—	(145)	(145)	13	(10)	3
Settlements	(1)	239	238	—	—	—	(12)	30	18
December 31, 2012 Balance	$36	$(290)	$(254)	$—	$(144)	$(144)	$8	$(9)	$(1)
Unrealized gain (loss)	(8)	(12)	(20)	—	(14)	(14)	1	7	8
Purchases	—	—	—	—	—	—	6	(13)	(7)
Settlements	(4)	46	42	—	—	—	(8)	6	(2)
June 30, 2013 Balance	$24	$(256)	$(232)	$—	$(158)	$(158)	$7	$(9)	$(2)

(1) Changes in the fair value of NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs, NUG contracts and LCAPP contracts that are classified as Level 3 in the fair value hierarchy for the period ended June 30, 2013:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(2)	Model	RTO auction clearing prices	($4.10) to $6.40	$0.80	Dollars/MWH
NUG Contracts	$(232)	Model	Generation Electricity regional prices	700 to 6,087,000 $48.80 to $57.30	1,522,000 $52.30	MWH Dollars/MWH
LCAPP Contracts	$(158)	Model	Regional capacity prices	$158.60 to $187.60	$171.20	Dollars/MW-Day

FES

Recurring Fair Value Measurements	June 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$757	$—	$757	$—	$703	$—	$703
Derivative assets - commodity contracts	1	252	—	253	—	252	—	252

Derivative assets - FTRs	—	—	5	5	—	—	6	6
Equity securities(1)	333	—	—	333	294	—	—	294
Foreign government debt securities	—	54	—	54	—	61	—	61
U.S. government debt securities	—	19	—	19	—	27	—	27
Other(2)	—	105	—	105	—	104	—	104
Total assets	$334	$1,187	$5	$1,526	$294	$1,147	$6	$1,447
Liabilities								
Derivative liabilities - commodity contracts	$(9)	$(158)	$—	$(167)	$(3)	$(151)	$—	$(154)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(6)	(6)
Total liabilities	$(9)	$(158)	$(8)	$(175)	$(3)	$(151)	$(6)	$(160)
Net assets (liabilities)(3)	$325	$1,029	$(3)	$1,351	$291	$996	$—	$1,287

(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 $2 million and $94 million as of June 30, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with the 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 June 30, 2013 and December 31, 2012:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
January 1, 2012 Balance	$1	$(7)	$(6)
Unrealized gain (loss)	4	(4)	—
Purchases	9	(7)	2
Settlements	(8)	12	4
December 31, 2012 Balance	$6	$(6)	$—
Unrealized gain	—	4	4
Purchases	5	(10)	(5)
Settlements	(6)	4	(2)
June 30, 2013 Balance	$5	$(8)	$(3)

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 June 30, 2013:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(3)	Model	RTO auction clearing prices	($4.10) to $5.70	$0.60	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, AFS securities and notes receivable.

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 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 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 June 30, 2013 and December 31, 2012:

	June 30, 2013[1]			December 31, 2012[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,827	$14	$1,841	$1,827	$34	$1,861
FES	876	3	879	778	14	792
Equity securities						
FirstEnergy	$431	$25	$456	$293	$16	$309
FES	313	20	333	281	13	294

(1) Excludes short-term cash investments: FE Consolidated - $116 million; FES - $58 million.
(2) Excludes short-term cash investments: FE Consolidated - $326 million; FES - $196 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 months and six months ended June 30, 2013 and 2012 were as follows:

Three Months Ended

June 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$638	$16	$(11)	$(46)	$22
FES	235	13	(8)	(38)	15

June 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$131	$17	$(15)	$(3)	$18
FES	25	13	(11)	(3)	11

Six Months Ended

June 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,177	$40	$(16)	$(53)	$48
FES	487	33	(11)	(45)	28

June 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$382	$37	$(28)	$(7)	$33

FES	109	26	(19)	(6)	18

22

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 June 30, 2013 and December 31, 2012:

	June 30, 2013			December 31, 2012		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$47	$—	$47	$54	$30	$84

Investments in emission allowances, employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $640 million as of June 30, 2013, and $644 million as of December 31, 2012, 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:

	June 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$17,212	$18,388	$16,957	$19,460
FES	3,016	3,126	4,194	4,524

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 June 30, 2013 and December 31, 2012.

During the first quarter of 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

Also during the first quarter of 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million

(FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility. In June 2013, the SPEs formed by the Ohio Companies issued $445 million of phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71% and pay $30 million of make-whole premiums associated with such redemptions which will also be recovered. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

9. 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 relating 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. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2031.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating interest rates and commodity prices. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $6 million and $10 million as of June 30, 2013 and December 31, 2012, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $9 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting 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 treated 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. No forward starting swap agreements accounted for as a cash flow hedge were outstanding as of June 30, 2013 or December 31, 2012. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $63 million and $70 million as of June 30, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

Refer to Note 5, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three and six months ended June 30, 2013 and 2012.

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. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of June 30, 2013 and December 31, 2012, 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 $60 million and $79 million as of June 30, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $16 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $5 million and $6 million during the three months ended June 30, 2013 and 2012, respectively and $11 million during the six months ended June 30, 2013 and 2012. In connection with the redemptions of senior notes by FES and taxable bonds by CEI and OE during the three months ended June 30, 2013, unamortized gains associated with fixed for floating interest rate swap agreements of $8 million were included in the loss on debt redemptions in the Consolidated Statements of Income (Loss) of FirstEnergy for the three and six months ended June 30, 2013. Refer to Note 8, Fair Value Measurements - Long-Term Debt and Other Long-Term Obligations, for additional information regarding FirstEnergy's debt redemptions during the three and six months ended June 30, 2013.

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. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy’s coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs.

As of June 30, 2013, FirstEnergy’s net asset position under commodity derivative contracts was $85 million, which related to FES positions. Under these commodity derivative contracts, FES posted $45 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $8 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of June 30, 2013, an adverse change of 10% in commodity prices would decrease net income by approximately $18 million during the next twelve months.

NUGs

As of June 30, 2013, FirstEnergy's net liability position under NUG contracts was $232 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.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintains two LCAPP contracts, which are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expects to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts are reflected on the Consolidated Balance Sheets as derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts are subject to regulatory accounting, changes in their fair value do not impact earnings.

FTRs

As of June 30, 2013, FirstEnergy's and FES's net liability position under FTRs was $2 million and FES posted $7 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 the PJM RTO. The PJM RTO 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 the RTO, 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 June 30, 2013	December 31, 2012	Derivative Liabilities	Fair Value June 30, 2013	December 31, 2012
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$166	$153	Commodity Contracts	$(133)	$(119)
FTRs	7	7	FTRs	(9)	(7)
	173	160		(142)	(126)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs	(256)	(290)
Deferred Charges and Other Assets - Other			LCAAP	(158)	(144)
Commodity Contracts	87	99	Noncurrent Liabilities - Other		
FTRs	—	1	Commodity Contracts	(35)	(36)
NUGs	24	36	FTRs	—	(2)
	111	136		(449)	(472)
Derivative Assets	$284	$296	Derivative Liabilities	$(591)	$(598)

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. 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 instruments 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		
June 30, 2013	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$253	$(149)	$(5)	$99
FTRs	7	(7)	—	—
NUG contracts	24	—	—	24
	$284	$(156)	$(5)	$123
Derivative Liabilities				
Commodity contracts	$(168)	$149	$16	$(3)

FTRs	(9)	7	2	—
NUG contracts	(256)	—	—	(256)
LCAPP contracts	(158)	—	—	(158)
	$(591)	$156	$18	$(417)

December 31, 2012	Fair Value	Amounts Not Offset in Consolidated Balance Sheet		
		Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$252	$(142)	$(5)	$105
FTRs	8	(8)	—	—
NUG contracts	36	—	—	36
	$296	$(150)	$(5)	$141
Derivative Liabilities				
Commodity contracts	$(155)	$142	$12	$(1)
FTRs	(9)	8	1	—
NUG contracts	(290)	—	—	(290)
LCAPP contracts	(144)	—	—	(144)
	$(598)	$150	$13	$(435)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of June 30, 2013:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	29	38	(9)	MWH
FTRs	70	—	70	MWH
NUGs	12	—	12	MWH
LCAPP	408	—	408	MW
Natural Gas	48	—	48	mmBTU

The effect of derivative instruments not in a hedging relationship on the Consolidated Statements of Income (Loss) during the three months and six months ended June 30, 2013 and 2012, are summarized in the following tables:

	Three Months Ended June 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Loss Recognized in:				
Other Operating Expense	$(10)	$(1)	$—	$(11)
Realized Gain (Loss) Reclassified to:				
Revenues	$6	$5	$—	$11
Purchased Power Expense	(2)	—	—	(2)
Other Operating Expense	—	(9)	—	(9)
Fuel Expense	2	—	—	2
2012				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense	$12	$12	$—	$24
Interest Expense	—	—	(20)	(20)
Realized Gain (Loss) Reclassified to:				
Revenues	$99	$5	$—	$104
Purchased Power Expense	(104)	—	—	(104)
Other Operating Expense	—	(18)	—	(18)
Fuel Expense	(1)	—	—	(1)

	Six Months Ended June 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Loss Recognized in:				
Other Operating Expense	$(15)	$(2)	$—	$(17)
Realized Gain (Loss) Reclassified to:				
Revenues	$16	$12	$—	$28
Purchased Power Expense	(13)	—	—	(13)
Other Operating Expense	—	(18)	—	(18)
Fuel Expense	2	—	—	2
2012				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense	$65	$17	$—	$82
Interest Expense	—	—	(20)	(20)
Realized Gain (Loss) Reclassified to:				
Revenues	$213	$11	$—	$224
Purchased Power Expense	(221)	—	—	(221)

Other Operating Expense	—	(41)	—	(41)
Fuel Expense	(1)	—	—	(1)

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three and six months ended June 30, 2013 and 2012, are summarized in the following tables:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended June 30			
	NUGs	LCAPP	Regulated FTRs	Total
	(In millions)			
2013				
Unrealized Loss on Derivative Instrument	$(38)	$(12)	$—	$(50)
Realized Gain on Derivative Instrument	20	—	1	21
2012				
Unrealized Loss on Derivative Instrument	$(54)	$(145)	$—	$(199)
Realized Gain on Derivative Instrument	61	—	5	66

Derivatives Not in a Hedging Relationship with Regulatory Offset	Six Months Ended June 30			
	NUGs	LCAPP	Regulated FTRs	Total
	(In millions)			
2013				
Unrealized Loss on Derivative Instrument	$(20)	$(14)	$—	$(34)
Realized Gain on Derivative Instrument	43	—	—	43
2012				
Unrealized Loss on Derivative Instrument	$(133)	$(145)	$(1)	$(279)
Realized Gain on Derivative Instrument	133	—	9	142

The following tables provide a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during the three months and six months ended June 30, 2013 and 2012:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended June 30			
	NUGs	LCAPP	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of April 1, 2013	$(213)	$(146)	$(1)	$(360)
Additions/Change in value of existing contracts	(38)	(12)	—	(50)
Settled contracts	20	—	1	21
Outstanding net liability as of June 30, 2013	$(231)	$(158)	$—	$(389)
Outstanding net liability as of April 1, 2012	$(300)	$—	$(5)	$(305)
Additions/Change in value of existing contracts	(54)	(145)	—	(199)
Settled contracts	61	—	5	66
Outstanding net liability as of June 30, 2012	$(293)	$(145)	$—	$(438)

Derivatives Not in a Hedging Relationship with Regulatory Offset	Six Months Ended June 30			
	NUGs	LCAPP	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of January 1, 2013	$(254)	$(144)	$—	$(398)

Additions/Change in value of existing contracts	(20)	(14)	—	(34)
Settled contracts	43	—	—	43
Outstanding net liability as of June 30, 2013	$(231)	$(158)	$—	$(389)
Outstanding net liability as of January 1, 2012	$(293)	$—	$(8)	$(301)
Additions/Change in value of existing contracts	(133)	(145)	(1)	(279)
Settled contracts	133	—	9	142
Outstanding net liability as of June 30, 2012	$(293)	$(145)	$—	$(438)

10. 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.

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.

The following table summarizes the changes to the ARO balances during 2013:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, December 31, 2012	$1,599	$965
Liabilities settled	(10)	(11)
Accretion	55	33
Revisions in estimated cash flows	151	151
Balance, June 30, 2013	$1,795	$1,138

Revisions to the estimated cash flows associated with the ARO liability of FES increased the liability by $151 million. The revision in estimates for the ARO balance relates primarily to increased cost estimates for the closure of LBR. The revised cost estimates were the result of a Closure Plan submitted to the PA DEP by FG on March 28, 2013, which provides for placing a final cap over LBR. See Note 12, Commitments, Guarantees, and Contingencies for additional information related to the closure of LBR.

11. 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 FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

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 residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired, however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. 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.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC has scheduled a hearing for August 20, 2013, to discuss the reports.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order requiring the utilities to submit several reports between March 29 and August 30, 2013, 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 requires 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 continues to respond to the requirements in the order consistent with the schedule set forth therein.

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, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, 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 September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU has transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. The updated filing now represents an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). Hearings are currently scheduled in the rate case for mid-September through mid-November. JCP&L is expected to file its rebuttal testimony on August 7, 2013.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed.

The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. JCP&L intends to vigorously pursue its position in the base rate case and full recovery of the costs associated with the major storm events of 2011 and 2012 but we cannot predict the outcome of these proceedings.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation 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);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM 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 PJM proceedings. The Ohio Companies have also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing. The PUCO issued an

Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at levels established in the existing 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);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional provisions, including:

- 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 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.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO issued an entry on rehearing denying the Ohio Companies' application for rehearing, in part, but authorizing the Ohio Companies' to receive 20% of any revenues obtained from bidding energy efficiency and demand response 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.

Additionally, under SB221, electric utilities and electric service companies in Ohio are required to serve part of their load from renewable energy resources measured by an annually increasing percentage amount. In August and October 2009 and in August 2010, the Ohio Companies conducted RFPs to secure RECs. The RECs acquired through these three RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and contribute toward meeting the benchmark for future years. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies will recover the costs of acquiring these RECs. The PUCO selected auditors to perform a financial and management audit, and final audit reports were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state all renewable obligations that the auditor characterized as excessive. A hearing for this matter commenced on February 19, 2013, and concluded on February 25, 2013. A decision of the PUCO is expected in the third quarter of 2013.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Companies recently reported that all of the Ohio Companies met their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies intend to conduct an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to provide comments on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. The PUCO has scheduled a series of workshops for the remainder of 2013, the first of which commenced on July 9, 2013. The Ohio Companies cannot predict the outcome of this investigation.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expired on May 31, 2013, 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 descending clock auctions, competitive requests for proposals and spot market purchases. On November 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSPs that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies filed revised proposals on the retail market enhancements on November 14, 2012. A final order was entered on February 15, 2013, which addressed minor changes to the Pennsylvania Companies' revised enhancement proposals and ordered two choices for cost recovery of those programs. On February 28, 2013, the Pennsylvania Companies filed a petition to amend the August 16, 2012, order related to the description of how the hourly industrial product is to be priced. On April 4, 2013, the PPUC entered a Final Order postponing the implementation of one of the retail market enhancements. On March 20, 2013, answers supporting and opposing the Pennsylvania Companies' February 28 petition were filed by several parties. On July 16, 2013, the PPUC entered an order granting the Pennsylvania Companies' February 28, 2013 petition, thereby amending its August 16, 2012 order and clarifying the description of the hourly industrial product pricing. The Pennsylvania Companies are actively implementing their DSPs as of June 1, 2013.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. In April 2010, ME and PN filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC's March 3, 2010 Order. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal on February 28, 2012, and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari on October 9, 2012. On July 13, 2011, ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania for the purpose of obtaining an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. Proceedings in the U.S. District Court effectively were suspended until conclusion of the proceedings before the United States Supreme Court. Pursuant to procedural orders issued by U.S. District Court Judge Gardner, on December 21, 2012, the PPUC submitted its motion to dismiss the U.S. District Court proceedings. ME and PN submitted their answers on January 9, 2013, and subsequent pleadings were submitted by the PPUC, ME and PN. Oral argument on the PPUC motion to dismiss took place on May 20, 2013, and the PPUC motion now is pending before the court.

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN's annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal transmission losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC's approval in May 2010 authorized an increase to the TSC for ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted an interim report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. The Pennsylvania Companies are expected to report their final energy efficiency and demand reduction results for the period ending May 31, 2013, by November 15, 2013.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013 the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings have been held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013 providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

In February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all RECs associated with the energy and capacity that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, opposed the petition. On November 22, 2011, the WVPSC granted ownership of all RECs produced by the facilities to MP, and held that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility under PURPA owns the RECs associated with that purchase. The West Virginia Supreme Court upheld the WVPSC's decision. The City of New Martinsville and Morgantown Energy Associates filed petitions at FERC alleging the WVPSC order violated PURPA and requested that FERC initiate an enforcement action. On April 24, 2012, FERC issued an order declining to act on the petitions and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. MP and PE filed for rehearing of FERC's order, which was denied on September 20, 2012. The City of New Martinsville filed a complaint in the U.S. District Court for the Southern District of West Virginia on June 1, 2012, alleging that the WVPSC order violates PURPA. Morgantown Energy Associates has joined in filing a similar complaint and requesting damages in the same U.S. District Court. MP and PE filed for judgment on the pleadings in both cases on January 25, 2013. The matters are pending in the District Court. The RECs are being used for compliance purposes and regardless of the final resolution of the ownership issue, MP and PE would expect to recover from customers costs incurred for RECs for compliance.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE have filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposes a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make unhedged electricity and capacity purchases from the spot market, which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to worsen due to a projected increase in annual load growth of approximately 1.4%. MP and PE will file a base rate case no later than six months from the completion of the transaction. On February 11, 2013, the WVPSC issued an order adopting a procedural schedule for this matter and testimony and briefing has followed. MP and PE also filed with FERC for authorization to effect these transfers and on April 23, 2013, FERC issued an order authorizing the transfers. MP's application for FERC authorization to effect the financing was approved on May 13, 2013. Hearings were held at the WVPSC in late May and briefs and reply briefs have been submitted. The matter is awaiting decision from the WVPSC.

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, 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 items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the 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 power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialization) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit. The PUCO and ICC also filed for review with that court. The Dayton Power & Light Company filed a Petition for Review with the U.S. Court of Appeals for the D.C. Circuit, and on May 2, 2013, FirstEnergy intervened in that proceeding. These appeals have been consolidated for briefing and disposition in the Seventh Circuit.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the New York Independent System Operator region and; (2) the PJM region and the FERC-jurisdictional members of the Southeastern Regional Transmission Planning region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that would have otherwise been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of the dispute are discussed below under "MISO Multi-Value Project Rule Proposal." In addition, FERC denied recovery of certain charges that collectively can be described as "exit fees" by means of ATSI's transmission rate totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project and the exit fee issue. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC that, if accepted by FERC, should resolve certain of the exit fee issues. Thereafter, the OCC protested the December 21, 2012 settlement filing, which remains pending before FERC. In a prior order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. On November 19, 2012, ATSI filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit of FERC's ruling on the "legacy RTEP" issue, and ATSI's initial brief was filed with that court on April 11, 2013. FERC filed its initial brief on June 25, 2013. The briefing schedule extends through August 30, 2013.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP project that was approved by MISO's Board prior to the June 1, 2011 effective date of FirstEnergy's integration into PJM would be allocated to and charged to ATSI. MISO estimated that approximately $16 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction. In addition, the MISO's MVP tariffs could assess costs on PJM loads that purchase energy that has flowed over the transmission systems into the MISO.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers. FirstEnergy asserts legal, factual and policy arguments. To date, FERC has responded in a series of orders that may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two tracks: litigation related to MISO's generic MVP cost allocation proposal; and litigation related to MISO's "Schedule

39" tariff that purports to charge the MVP costs to ATSI.

Regarding the first litigation track, in 2010 and 2011 FERC issued orders that approved the MISO proposal. On October 31, 2011, FirstEnergy filed a Petition of Review of those orders with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November 2011, the appeals were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit. Briefs were filed in late 2012 and early 2013, and the court heard oral arguments on April 10, 2013. On June 7, 2013, the Seventh Circuit issued an order that ratified FERC's acceptance of the MISO's proposed MVP tariff. The Seventh Circuit held, in relevant part, that: (i) MISO's generic MVP cost allocation proposal was just and reasonable under the FPA; and (ii) that ATSI's arguments that it should not have to pay MVP charges were being considered in the second litigation track (the "Schedule 39" proceeding") and therefore were not ripe for decision by the court. The parties that opposed the generic MVP tariff - led by the ICC and the State of Michigan - have ninety days (or until September 5, 2013) to file for appeal with the U.S. Supreme Court. FirstEnergy continues to evaluate the Seventh Circuit's order and its substantive and procedural options.

Regarding the second litigation track, in February 2012, FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. FERC set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb Project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb Project cost responsibility. The hearings took place in April 2013, and on July 16, 2013 the ALJ issued an Initial Decision ruling that ATSI must pay the "Schedule 39" MVP costs. Briefs on Exceptions to the Initial Decision and Briefs Opposing Exceptions are due on August 15 and September 4, 2013, respectively. Thereafter the question of whether ATSI must pay MVP charges as determined under MISO's "Schedule 39" will be presented to FERC for final decision.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

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 U.S. Court of Appeals for 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, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. On March 13, 2013, the Ninth Circuit issued a briefing schedule with the final briefs due on October 9, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another 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 filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has 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.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012 subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project. FirstEnergy cannot predict the outcome of these matters or estimate the possible loss or range of loss.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. The previous license expired on February 28, 2013. On May 9, 2013, FERC issued the new license for a term of 40 years. JCP&L and PSEG have notified FERC of their acceptance of the license and are implementing the license conditions.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FG. FG holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC's regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FG initiated the ILP relicensing process by filing its notice of intent to relicense and related documents in the license docket.

Section 15 of the FPA contemplates that third parties may file a "competing application" to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. FG believes it is entitled to a statutory “incumbent preference” under Section 15 and that it ultimately should prevail in these proceedings. Nevertheless, the Seneca Nation's pleadings reflect the Nation's apparent intent to obtain the license for the facility, and to assume ownership and operation of the facility as contemplated by the statute.

The Seneca Nation and certain other intervenors have asked FERC to redefine the “project boundary” of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy's petition, including motions to dismiss FirstEnergy's petition. The “project boundary” issue is pending before FERC.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On January 7, 2013, FirstEnergy and the Seneca Nation submitted their respective reports for the 2012 study season. On January 31 and February 1, 2013, respectively, the Seneca Nation and FirstEnergy each submitted their respective proposed study plans for the 2013 study season. On March 4, 2013, the Seneca Nation and other parties submitted comments regarding FirstEnergy's proposed study plans. In its comments, the Seneca Nation alleges that FirstEnergy does not hold the real estate rights necessary to operate a hydroelectric project in circumstances where there is flowage over the Seneca Nation's lands. On April 3, 2013, FirstEnergy filed its response to these and other assertions by the Seneca Nation and its allied parties. On May 3, 2013, FERC's Director of the Office of Energy Projects issued FERC Staff's study plan determinations for the 2013 study year. The Director determined that water level fluctuations in the lower reservoir due to hydroelectric project operations have no discernible effect on reservoir lands or environmental resources. This finding is expected to strengthen FirstEnergy's position that the project boundary should be defined to exclude the U.S. Army Corps of Engineers dam and reservoir facilities. FERC Staff's determinations also largely adopted FirstEnergy's position and arguments as to the proper scope of environmental studies for the 2013 study season. The study processes will extend through approximately November 2013.

On July 3, 2013, FirstEnergy and the Seneca Nation each submitted "Preliminary License Proposals" in the relicensing dockets. These submissions are intended to be non-binding indications of types of project upgrades that may be proposed in the parties' respective final licensing applications, as well as an indication of the scope and direction of the parties' plans for the upcoming final licensing applications. FirstEnergy is evaluating the Seneca Nation's proposal.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, on January 3, 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. 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.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. PJM proposed an effective date for these Tariff changes of February 5, 2013. On February 5, 2013, FERC Staff issued a deficiency letter to PJM requesting additional information on certain components of the proposed MOPR reform, including the exemptions and resources qualifying for the MOPR. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also required PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 decision. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and the data that is available in the public domain about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer price of the assets was approximately $21.5 million and the estimated conversion cost was approximately $60 million. The transfer of Eastlake Units 4 and 5 was completed on January 31, 2013. ATSI completed the conversion in July 2013 for Eastlake Unit 5 and is expected to complete the conversion of Eastlake Unit 4 by June 1, 2014. The transfer of each of the remaining units and conversion to synchronous condensers will occur when the use of the unit for RMR purposes is no longer required. On January 22, 2013, ATSI requested clarification or, in the alternative, rehearing with respect to a statement in the FERC order authorizing the transfer that ATSI's current formula rate does not include the accounts and components necessary to allow for recovery of the costs associated with acquisition of the transferred assets and that ATSI must make a filing under Section 205 of the FPA in order to recover those costs. ATSI believes its formula rate currently includes the necessary accounts and components to allow for such recovery and that a Section 205 filing is not required. On August 5, 2013, FERC clarified that the issue of whether the cost of the transferred facilities and any conversion costs could be included in ATSI’s formula rates is more appropriately addressed during ATSI’s yearly formula rate update process.

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. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $61.5 million in revenues that they are entitled to receive as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FirstEnergy's request for rehearing is pending before FERC.

12. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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 June 30, 2013, outstanding guarantees and other assurances aggregated approximately $3.9 billion, consisting of parental guarantees ($895 million), subsidiaries' guarantees ($2,240 million) and other guarantees ($725 million).

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 June 30, 2013, FES has posted collateral of $86 million. The Regulated Distribution segment has posted collateral of $17 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 as of June 30, 2013:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$437	$6	$44	$487
BB+/Ba1 Credit Ratings	$489	$6	$58	$553
Full impact of credit contingent contractual obligations	$696	$58	$92	$846

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of June 30, 2013, 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 and AE Supply would be required to post $86 million and $3 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. 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 new facility.

In connection with the new facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the new facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

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.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx 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.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania alleging NSR violations at the coal-fired Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from ME in 1999) and ME. Specifically, these suits allege that “modifications” at Portland Units 1 and 2 occurred between 1980 and 2005 without pre-construction NSR permitting in violation of the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In February 2012, GenOn announced its plans to deactivate the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On March 28, 2013, the Court entered summary judgment for ME, ruling that all of the New Jersey's and Connecticut's claims against ME were barred by the applicable statute of limitations and dismissing all of their claims with prejudice. On July 18, 2013, the Court entered a consent decree between the other defendants and the plaintiffs settling all other claims and requiring permanent closure of the Portland Station by June 1, 2014.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. ME, as a former owner of the facilities, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which held oral argument on May 15, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the

NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. 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. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional 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. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the PSD provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia decided that CAIR violated the CAA but allowed CAIR to remain in effect to “temporarily preserve its environmental values” until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), 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. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-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 exemption through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an exemption through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Mansfield stations. 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. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is currently estimated to be approximately $650 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. On July 9, 2013, FirstEnergy announced that the Hatfield's Ferry and Mitchell stations are expected to be deactivated by October 9, 2013, subject to review for reliability impacts, if any, by PJM.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. We have asserted force majeure defenses for delivery shortfalls under certain agreements, and we are in discussion with the applicable counterparties. Under one agreement, we have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payment of approximately $45 million, and agreed to pay liquidated damages for delivery shortfalls, if any, for 2013 and 2014. As to another agreement, penalties of approximately $22 million for delivery shortfalls for 2012 could apply. If we fail to reach a resolution with applicable counterparties for the unresolved aspects of the agreements and it were ultimately determined that, contrary to our belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels), (2) prepare the United States for the impacts of climate change, and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW. The proposed new source performance standard of 1,000 lbs. CO_2/MWH, is roughly equivalent to the emission rate of a natural gas combined cycle unit and roughly 50 percent below the emission rate from coal-fired power plants operating today. On June 25, 2013, a Presidential memorandum directed EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013, and propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes 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.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. In June 2013, the period for finalizing the Section 316(b) regulation was extended to November 4, 2013. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

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 in excess of $150 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 these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River are expected to be deactivated, subject to PJM review, on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel 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 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulated with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. Depending on the content of the EPA's final effluent limitations rule and the specifics of any "alignment", the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by

December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities 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 Sheet as of June 30, 2013 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 $124 million have been accrued through June 30, 2013. Included in the total are accrued liabilities of approximately $82 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 possible losses 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 June 30, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate. The values of FirstEnergy's NDT 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 NDT. On June 18, 2013, FE submitted a revised $125 million parental guaranty for NRC review relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. On this date, FE also submitted to the NRC a revised $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's SAMA analysis. On December 28, 2012, the ASLB issued two decisions that granted FENOC's motion for summary dismissal of the remaining SAMA contention and denied the Intervenors' request for a new contention on the Davis-Besse Shield Building. The ASLB declined to terminate the adjudication. In an earlier order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance until further order. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the Intervenors' proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

In May 2013, four petitioners requested a hearing on an NRC LAR submitted by FENOC to amend the Technical Specifications for the Davis-Besse plant to support plant operations following replacement of the steam generators, which is scheduled to be completed in April 2014. The petitioners also challenge FENOC's ability to replace the steam generators at the Davis-Besse plant under the NRC regulations, 10 CFR §50.59 without submitting a formal LAR. On June 21, 2013, both the NRC Staff and FENOC filed oppositions to the request for a hearing.

By a letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff conducted several supplemental inspections, including an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues were understood, the extent of condition was identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. On December 28, 2012, the NRC issued a report on the 95002 Inspection that concluded that FENOC "did not provide assurance that the corrective actions for performance issues associated with the Occupational Exposure Control Effectiveness PI were sufficient to address the root and contributing causes and prevent recurrence." Moreover, the NRC also concluded that FENOC "did not adequately address corrective actions for the White NOV." As a result, the NRC will hold open both a parallel PI inspection finding on the occupational exposure issues and the White finding. The NRC will conduct a future inspection to verify the effectiveness of FENOC's corrective actions. Additional adverse findings by the NRC could result in additional NRC oversight and further inspection activities.

By a letter dated January 17, 2013, the NRC notified FENOC that the Perry plant would remain in Column 3 of the action matrix for the NRC reactor oversight process. It stated that although “Perry meets the definition in Inspection Manual Chapter 0305 for Multiple/Repetitive Degraded Cornerstone, Column 4, of the Action Matrix,” current performance issues are well understood and appear to be limited to occupational radiation safety, at present and thus the regulatory actions specified for Column 3 of the Action Matrix are more appropriate. The NRC also noted that Perry would move to Column 4 if: (1) the follow-up 95002 inspection, scheduled for completion in the May-July 2013 timeframe, identifies a significant weakness in Perry's performance; (2) Perry is unable to complete corrective actions necessary to permit the follow-up 95002 inspection to be completed before the end of July 2013; or (3) if another Greater-than-Green PI or finding is identified (other than a change of color for the current Occupational Exposure Control Effectiveness PI issue). Additional adverse findings by the NRC could result in further inspection activities and/or other regulatory actions.

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 FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal / interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only.

Other Legal Matters

On July 13, 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death, negligence, and negligent infliction of emotional distress claims. Plaintiff's decedent, Carrie Goretzka, was fatally electrocuted when she contacted a downed power line at her residence in Irwin, Pennsylvania. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty. The settlement is subject to PPUC approval.

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 other potentially material items not otherwise discussed above are described under Note 11, 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.

13. 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 under GAAP for FES and FirstEnergy and as a financing lease for FG.

The Consolidating Statements of Income and Comprehensive Income for the three months and six months ended June 30, 2013 and 2012, Consolidating Balance Sheets as of June 30, 2013 and December 31, 2012, and Consolidating Statements of Cash Flows for the six months ended June 30, 2013 and 2012, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. 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
(Unaudited)

For the Three Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,425	$560	$457	$(983)	$1,459
OPERATING EXPENSES:					
Fuel	—	286	46	—	332
Purchased power from affiliates	1,050	—	70	(983)	137
Purchased power from non-affiliates	524	—	—	—	524
Other operating expenses	175	70	131	12	388
Provision for depreciation	2	34	44	(2)	78
General taxes	19	8	7	—	34
Total operating expenses	1,770	398	298	(973)	1,493
OPERATING INCOME (LOSS)	(345)	162	159	(10)	(34)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(32)	—	—	—	(32)
Investment income	1	—	(14)	(5)	(18)
Miscellaneous income, including net income from equity investees	171	3	—	(168)	6
Interest expense — affiliates	(5)	(1)	(3)	4	(5)
Interest expense — other	(12)	(27)	(14)	14	(39)
Capitalized interest	1	—	9	—	10
Total other income (expense)	124	(25)	(22)	(155)	(78)
INCOME (LOSS) BEFORE INCOME TAXES	(221)	137	137	(165)	(112)
INCOME TAXES (BENEFITS)	(150)	54	52	3	(41)
NET INCOME (LOSS)	$(71)	$83	$85	$(168)	$(71)
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME (LOSS)	$(71)	$83	$85	$(168)	$(71)
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(5)	(5)	—	5	(5)
Amortized loss on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available-for-sale securities	(8)	—	(8)	8	(8)
Other comprehensive loss	(14)	(5)	(8)	13	(14)
Income benefits on other comprehensive loss	(5)	(2)	(4)	6	(5)

Other comprehensive loss, net of tax	(9)	(3)	(4)	7	(9)
COMPREHENSIVE INCOME (LOSS)	$(80)	$80	$81	$(161)	$(80)

49

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Six Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$2,921	$1,097	$897	$(1,926)	$2,989
OPERATING EXPENSES:					
Fuel	—	533	99	—	632
Purchased power from affiliates	2,063	—	132	(1,926)	269
Purchased power from non-affiliates	1,029	—	—	—	1,029
Other operating expenses	337	145	262	24	768
Provision for depreciation	3	66	88	(3)	154
General taxes	39	19	13	—	71
Total operating expenses	3,471	763	594	(1,905)	2,923
OPERATING INCOME (LOSS)	(550)	334	303	(21)	66
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income (loss)	2	—	4	(7)	(1)
Miscellaneous income, including net income from equity investees	363	4	—	(359)	8
Interest expense — affiliates	(7)	(2)	(4)	7	(6)
Interest expense — other	(37)	(55)	(29)	30	(91)
Capitalized interest	1	—	18	—	19
Total other income (expense)	219	(53)	(11)	(329)	(174)
INCOME (LOSS) BEFORE INCOME TAXES	(331)	281	292	(350)	(108)
INCOME TAXES (BENEFITS)	(262)	107	110	6	(39)
NET INCOME (LOSS)	$(69)	$174	$182	$(356)	$(69)
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME (LOSS)	$(69)	$174	$182	$(356)	$(69)
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(11)	(10)	—	10	(11)
Amortized loss on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	(3)	—	(3)	3	(3)
Other comprehensive loss	(16)	(10)	(3)	13	(16)
Income benefits on other comprehensive loss	(6)	(4)	(2)	6	(6)

Other comprehensive loss, net of tax	(10)	(6)	(1)	7	(10)
COMPREHENSIVE INCOME (LOSS)	$(79)	$168	$181	$(349)	$(79)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended June 30, 2012	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,430	$636	$473	$(1,083)	$1,456
OPERATING EXPENSES:					
Fuel	—	336	44	—	380
Purchased power from affiliates	1,156	—	60	(1,083)	133
Purchased power from non-affiliates	434	—	—	—	434
Other operating expenses	107	100	172	14	393
Provision for depreciation	1	30	39	(1)	69
General taxes	20	8	4	—	32
Total operating expenses	1,718	474	319	(1,070)	1,441
OPERATING INCOME (LOSS)	(288)	162	154	(13)	15
OTHER INCOME (EXPENSE):					
Investment income	—	5	7	(6)	6
Miscellaneous income, including net income from equity investees	279	19	—	(278)	20
Interest expense — affiliates	(5)	(2)	(1)	6	(2)
Interest expense — other	(24)	(26)	(14)	16	(48)
Capitalized interest	—	1	8	—	9
Total other income (expense)	250	(3)	—	(262)	(15)
INCOME (LOSS) BEFORE INCOME TAXES	(38)	159	154	(275)	—
INCOME TAXES (BENEFITS)	(37)	(7)	42	3	1
NET INCOME (LOSS)	$(1)	$166	$112	$(278)	$(1)
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME (LOSS)	$(1)	$166	$112	$(278)	$(1)
OTHER COMPREHENSIVE INCOME:					
Pensions and OPEB prior service costs	8	7	—	(7)	8
Amortized loss on derivative hedges	1	—	—	—	1
Change in unrealized gain on available for sale securities	3	—	3	(3)	3
Other comprehensive income	12	7	3	(10)	12
Income taxes on other comprehensive income	2	3	1	(4)	2
Other comprehensive income, net of tax	10	4	2	(6)	10

COMPREHENSIVE INCOME	$9	$170	$114	$(284)	$9

51

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Six Months Ended June 30, 2012	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$2,920	$1,178	$867	$(1,993)	$2,972
OPERATING EXPENSES:					
Fuel	—	576	99	—	675
Purchased power from affiliates	2,121	—	122	(1,993)	250
Purchased power from non-affiliates	921	—	—	—	921
Other operating expenses	183	192	288	25	688
Provision for depreciation	2	60	73	(3)	132
General taxes	40	18	11	—	69
Total operating expenses	3,267	846	593	(1,971)	2,735
OPERATING INCOME (LOSS)	(347)	332	274	(22)	237
OTHER INCOME (EXPENSE):					
Investment income	1	9	12	(10)	12
Miscellaneous income, including net income from equity investees	537	19	—	(532)	24
Interest expense — affiliates	(9)	(3)	(2)	10	(4)
Interest expense — other	(47)	(52)	(21)	31	(89)
Capitalized interest	—	2	16	—	18
Total other income (expense)	482	(25)	5	(501)	(39)
INCOME BEFORE INCOME TAXES	135	307	279	(523)	198
INCOME TAXES (BENEFITS)	14	(8)	65	6	77
NET INCOME	$121	$315	$214	$(529)	$121
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$121	$315	$214	$(529)	$121
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	3	3	—	(3)	3
Amortized loss on derivative hedges	(4)	—	—	—	(4)
Change in unrealized gain on available-for-sale securities	13	—	13	(13)	13
Other comprehensive income	12	3	13	(16)	12
Income taxes on other comprehensive income	4	1	5	(6)	4

Other comprehensive income, net of tax	8	2	8	(10)	8
COMPREHENSIVE INCOME	$129	$317	$222	$(539)	$129

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	541	—	—	—	541
Affiliated companies	326	477	325	(693)	435
Other	86	30	6	—	122
Notes receivable from affiliated companies	573	14	590	(1,057)	120
Materials and supplies	69	172	213	—	454
Derivatives	170	—	—	—	170
Prepayments and other	83	39	7	—	129
	1,848	734	1,141	(1,750)	1,973
PROPERTY, PLANT AND EQUIPMENT:					
In service	114	6,234	6,598	(383)	12,563
Less — Accumulated provision for depreciation	34	1,964	2,798	(186)	4,610
	80	4,270	3,800	(197)	7,953
Construction work in progress	19	99	898	—	1,016
	99	4,369	4,698	(197)	8,969
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,270	—	1,270
Investment in affiliated companies	5,334	—	—	(5,334)	—
Other	—	12	—	—	12
	5,334	12	1,270	(5,334)	1,282
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	239	—	(239)	—
Customer intangibles	103	—	—	—	103
Goodwill	24	—	—	—	24
Property taxes	—	14	22	—	36
Unamortized sale and leaseback costs	—	—	—	164	164
Derivatives	87	—	—	—	87
Other	144	245	13	(163)	239
	358	498	35	(238)	653
	$7,639	$5,613	$7,144	$(7,519)	$12,877
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$366	$514	$(22)	$859
Short-term borrowings-					
Affiliated companies	599	458	—	(1,057)	—
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	702	265	252	(705)	514

Other	120	136	—	—	256
Accrued taxes	7	14	20	(1)	40
Derivatives	140	—	—	—	140
Other	63	65	16	35	179
	1,632	1,308	802	(1,750)	1,992
CAPITALIZATION:					
Total equity	5,193	1,965	3,347	(5,312)	5,193
Long-term debt and other long-term obligations	712	1,875	789	(1,196)	2,180
	5,905	3,840	4,136	(6,508)	7,373
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	875	875
Accumulated deferred income taxes	12	—	770	(135)	647
Asset retirement obligations	—	171	967	—	1,138
Retirement benefits	26	224	—	—	250
Derivatives	35	—	—	—	35
Other	29	70	469	(1)	567
	102	465	2,206	739	3,512
	$7,639	$5,613	$7,144	$(7,519)	$12,877

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2012	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$3	$—	$—	$3
Receivables-					
Customers	483	—	—	—	483
Affiliated companies	232	417	478	(748)	379
Other	56	19	16	—	91
Notes receivable from affiliated companies	366	7	607	(704)	276
Materials and supplies	66	231	208	—	505
Derivatives	158	—	—	—	158
Prepayments and other	38	39	10	—	87
	1,399	716	1,319	(1,452)	1,982
PROPERTY, PLANT AND EQUIPMENT:					
In service	91	5,899	6,391	(384)	11,997
Less — Accumulated provision for depreciation	32	1,915	2,646	(185)	4,408
	59	3,984	3,745	(199)	7,589
Construction work in progress	34	230	877	—	1,141
	93	4,214	4,622	(199)	8,730
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,283	—	1,283
Investment in affiliated companies	4,972	—	—	(4,972)	—
Other	—	12	—	—	12
	4,972	12	1,283	(4,972)	1,295
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	313	—	(313)	—
Customer intangibles	110	—	—	—	110
Goodwill	24	—	—	—	24
Property taxes	—	14	22	—	36
Unamortized sale and leaseback costs	—	—	—	119	119
Derivatives	99	—	—	—	99
Other	160	194	5	(106)	253
	393	521	27	(300)	641
	$6,857	$5,463	$7,251	$(6,923)	$12,648
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$586	$537	$(22)	$1,102
Short-term borrowings-					
Affiliated companies	358	346	—	(704)	—
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	748	143	583	(748)	726

Other	63	96	—	—	159
Accrued taxes	126	25	20	—	171
Derivatives	124	—	—	—	124
Other	71	148	15	46	280
	1,491	1,348	1,155	(1,428)	2,566
CAPITALIZATION:					
Total equity	3,763	1,787	3,165	(4,952)	3,763
Long-term debt and other long-term obligations	1,482	2,009	834	(1,207)	3,118
	5,245	3,796	3,999	(6,159)	6,881
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	892	892
Accumulated deferred income taxes	28	—	714	(227)	515
Asset retirement obligations	—	29	936	—	965
Retirement benefits	26	215	—	—	241
Derivatives	37	—	—	—	37
Other	30	75	447	(1)	551
	121	319	2,097	664	3,201
	$6,857	$5,463	$7,251	$(6,923)	$12,648

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(687)	$390	$308	$(11)	$—
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	240	112	—	(352)	—
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(352)	(68)	11	(1,179)
Tender premiums	(67)	—	—	—	(67)
Other	(2)	(3)	—	—	(5)
Net cash provided from (used for) financing activities	901	(243)	(68)	(341)	249
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(7)	(163)	(180)	—	(350)
Nuclear fuel	—	—	(50)	—	(50)
Proceeds from asset sales	—	19	—	—	19
Sales of investment securities held in trusts	—	—	487	—	487
Purchases of investment securities held in trusts	—	—	(515)	—	(515)
Loans to affiliated companies, net	(207)	(7)	18	352	156
Customer acquisition costs	—	—	—	—	—
Other	—	3	—	—	3
Net cash used for investing activities	(214)	(148)	(240)	352	(250)
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

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2012	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(525)	$308	$446	$(10)	$219
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	52	30	—	82
Short-term borrowings, net	532	46	—	(578)	—
Redemptions and Repayments-					
Long-term debt	—	(63)	(87)	10	(140)
Short-term borrowings, net	—	—	(32)	32	—
Other	(1)	(4)	(1)	—	(6)
Net cash provided from (used for) financing activities	531	31	(90)	(536)	(64)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(44)	(164)	—	(213)
Nuclear fuel	—	—	(90)	—	(90)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	109	—	109
Purchases of investment securities held in trusts	—	—	(127)	—	(127)
Loans to affiliated companies, net	1	(308)	(84)	546	155
Other	(2)	(4)	—	—	(6)
Net cash used for investing activities	(6)	(339)	(356)	546	(155)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$—	$7	$—	$—	$7

14. SEGMENT INFORMATION

Financial information for each of FirstEnergy’s reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

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 in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). 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 derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, 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 approximately 18,000 MWs of capacity (including 885 MWs of capacity subject to RMR arrangements with PJM and 2,080 MWs of capacity planned to be deactivated by October 9, 2013) and also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Other/Corporate Segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. Reconciling adjustments primarily consist of elimination of intersegment transactions.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Reconciling Adjustments	Consolidated
	(In millions)					
June 30, 2013						
External revenues	$2,041	$180	$1,377	$ (31)	$(48)	$3,519
Internal revenues	—	—	176	—	(176)	—
Total revenues	2,041	180	1,553	(31)	(224)	3,519
Depreciation, amortization and deferrals	220	31	114	9	—	374
Investment income	9	—	(17)	2	(9)	(15)
Interest expense	135	22	61	38	—	256
Income taxes (benefits)	108	30	(207)	7	4	(58)
Net income (loss)	179	51	(339)	(52)	(3)	(164)
Total assets	26,936	4,797	17,910	514	—	50,157
Total goodwill	5,025	526	896	—	—	6,447
Property additions	283	97	185	21	—	586
June 30, 2012						
External revenues	$2,139	$184	$1,501	$ (23)	$(46)	$3,755
Internal revenues	—	—	209	—	(209)	—
Total revenues	2,139	184	1,710	(23)	(255)	3,755
Depreciation, amortization and deferrals	208	29	103	8	(1)	347
Investment income	19	1	6	1	(14)	13
Interest expense	135	23	71	45	—	274
Income taxes (benefits)	94	30	14	(25)	14	127
Net income (loss)	158	54	25	(41)	(8)	188
Total assets	25,787	4,473	17,216	572	—	48,048
Total goodwill	5,025	526	893	—	—	6,444
Property additions	177	59	132	26	—	394
Six Months Ended						
June 30, 2013						
External revenues	$4,253	$356	$2,791	$ (58)	$(94)	$7,248
Internal revenues	—	—	392	—	(392)	—
Total revenues	4,253	356	3,183	(58)	(486)	7,248
Depreciation, amortization and deferrals	422	60	225	20	—	727
Investment income	27	—	(1)	3	(26)	3
Interest expense	270	45	134	65	—	514
Income taxes (benefits)	234	61	(230)	(11)	4	58
Net income (loss)	389	102	(377)	(82)	—	32
Total assets	26,936	4,797	17,910	514	—	50,157
Total goodwill	5,025	526	896	—	—	6,447
Property additions	719	186	468	39	—	1,412

June 30, 2012						
External revenues	$4,493	$370	$3,020	$ (47)	$(93)	$7,743
Internal revenues	—	—	477	—	(475)	2
Total revenues	4,493	370	3,497	(47)	(568)	7,745
Depreciation, amortization and deferrals	425	58	203	16	(1)	701
Investment income	42	1	12	1	(32)	24
Interest expense	269	46	136	69	—	520
Income taxes (benefits)	187	66	97	(41)	40	349
Net income (loss)	317	112	166	(69)	(32)	494
Total assets	25,787	4,473	17,216	572	—	48,048
Total goodwill	5,025	526	893	—	—	6,444
Property additions	443	122	303	43	—	911

Item 2. Management’s Discussion and Analysis of Registrant and Subsidiaries

FIRSTENERGY CORP.

MANAGEMENT’S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Net loss in the second quarter of 2013 was $164 million, or basic and diluted losses of $0.39 per share of common stock, compared with net income of $187 million, or basic and diluted earnings of $0.45 per share of common stock in the second quarter of 2012. The principal reasons for the changes in basic earnings per share are summarized below.

Change In Basic Earnings (Losses) Per Share From Prior Year	Three Months Ended June 30	Six Months Ended June 30
Basic Earnings Per Share - 2012	$0.45	$1.18
Segment operating results[1] -		
Regulated Distribution	0.03	0.15
Regulated Transmission	—	(0.03)
Competitive Energy Services	(0.03)	(0.22)
Regulatory charges	(0.01)	(0.04)
Non-core asset sales/impairments	(0.01)	(0.02)
Merger-related costs	—	0.01
Merger accounting — commodity contracts	0.01	0.02
Trust securities impairments	(0.04)	(0.05)
Mark-to-market adjustments	0.02	(0.04)
Plant deactivation costs[2]	(0.78)	(0.73)
Debt redemption costs	(0.04)	(0.22)
Interest expense, net of amounts capitalized	—	(0.02)
Investment income	—	0.02
Income tax legislative changes - 2012	0.02	0.04
Change in effective tax rate	(0.02)	0.01
Other	0.01	0.02
Basic Earnings (Losses) Per Share - 2013	$(0.39)	$0.08

(1) Excludes amounts shown separately.
(2) Includes impairments of long lived assets of $0.71 per share, severance charges of $0.02 per share and a valuation reserve against net operating loss carryforwards of $0.05 per share recognized in the second quarter of 2013 related to the decision to deactivate Hatfield's Ferry and Mitchell generating units.

FirstEnergy continues to experience weak economic conditions across its multi-state utility service territory, as evidenced by relatively flat distribution sales over the last three years. This prolonged low demand environment, coupled with excess generation supply in the region, has caused a period of protracted low power and capacity prices. The PJM RPM Auction for 2016/2017 capacity that was conducted in May 2013 produced prices in the regions served by FirstEnergy's Competitive Energy Services Segment that were lower than expected. This result may be a broader indication of an underlying supply/demand imbalance that is expected to continue to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than FirstEnergy, or the industry at large, previously expected. FirstEnergy's estimated contracted competitive sales for 2013 are 107 million MWH and have exceeded its original target of 104 million MWH. The Competitive Energy Services Segment has adjusted its hedging strategy by slowing forward sales in order to capture potential future improvements in power prices. With the deactivation of certain of our generating units, we will have less self-generated electricity to sell. To mitigate the impact of this decrease, we are being more selective in the customers we target and focusing more on those customers with higher profit margins. Currently, FirstEnergy's estimated contracted competitive sales for 2014 are more than 75 million MWH. As FirstEnergy experiences these ongoing trends, it plans to fully review all facets of its operations for potential cost savings. In particular, FirstEnergy recently undertook a comprehensive review of competitive operations related to, among other things, plant economics, which resulted in the previously announced decision to deactivate the Hatfield's Ferry and Mitchell plants as discussed below. The reduction in capital expenditures at these facilities, including the $275 million decrease for MATS, is expected to total approximately $500 million over the next five years. FirstEnergy has also canceled or delayed certain planned investments in other generating facilities which are expected to further reduce the capital needs in our competitive generation fleet by approximately $375 million over that same period.

FirstEnergy has also identified and intends to implement additional cost control opportunities across the organization. These actions include reductions to medical and other employee benefits and other organizational changes, including a reduction in staffing of an additional 250 positions. FirstEnergy did not recognize any costs in the second quarter of 2013 associated with these actions as final plans were not completed. FirstEnergy expects to incur approximately $3 million (pre-tax) of severance related expenses in the third quarter of 2013.

Plant Impairments

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

Generating Units	MW Capacity	Location
Hatfield's Ferry, Units 1-3	1,710	Masontown, Pennsylvania
Mitchell, Units 2-3	370	Courtney, Pennsylvania

The decision to deactivate the plants was based on the cost of compliance with current and future environmental regulations in conjunction with the continued low market price for electricity. The total capacity of these plants represents approximately 10% of FirstEnergy's total generating capacity. Deactivating these plants is expected to reduce the cost of complying with MATS to approximately $650 million from $925 million. These deactivations are subject to review for reliability impacts, if any, by PJM, the RTO that controls the area where these power plants are located.

As a result of this decision, in the second quarter of 2013, 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 is included within the results of the Competitive Energy Services Segment.

Approximately 380 plant employees and generation related positions are expected to be affected by these plant deactivations. Eligible employees will receive severance benefits in 2013 that are currently estimated to be approximately $15 million (pre-tax) and were recognized in Other operating expenses in the Consolidated Statements of Income (Loss) in the second quarter of 2013.

Upon termination of operations at Hatfield's Ferry Units 1-3, AE Supply will have the right to redeem $235 million of its outstanding PCRBs at par.

Financial Plan

Earlier this year, FirstEnergy announced the 2013 financial plan intended to strengthen the balance sheet of the Competitive Energy Services Segment by reducing its debt by approximately $1.5 billion. Completion of the plan is expected to significantly improve credit metrics at our Competitive Energy Services Segment. This plan also includes the net transfer of 1,476 MW between AE Supply and MP of the Harrison and Pleasants power plants, for which AE Supply and MP await regulatory approval, and the proposed sale of up to 1,240 MW of unregulated hydro assets. Finally, as part of the 2013 financial plan, FirstEnergy announced earlier this year that it had expected to issue a modest amount of equity in late 2013.

In line with these efforts, FirstEnergy continued to execute its 2013 financial plan during the second quarter:

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- On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of redemption premiums paid.
- On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.
- In addition, during the second quarter FirstEnergy Corp. completed a $1.5 billion equity contribution to FES.

Additionally, in June 2013, the Ohio Companies, through newly formed limited liability SPEs, executed a securitization transaction that resulted in the issuance of $445 million of phase-in recovery bonds with a weighted average coupon of 2.48%. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71% and pay $30 million of make-whole premiums which will also be recovered. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020.

Instead of issuing a modest amount of equity in a new capital raising transaction or program, FirstEnergy expects to begin fulfilling certain share-based benefit plan and dividend reinvestment obligations through the issuance of authorized but unissued equity as opposed to its current practice of purchasing shares in the open market. FirstEnergy now believes that additional equity will not be necessary to support the 2013 financial plan. Accordingly, no additional issuances of equity are planned.

On May 8, 2013, FE, FES, and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

The Ohio Companies also have issued notices to redeem, subject to satisfying certain conditions, an additional $660 million of debt. These debt redemptions are expected to be completed in the third quarter of 2013.

Overall, these actions are expected to advance FirstEnergy's progress in achieving its financial goals, including strengthening the balance sheet, improving liquidity and maintaining credit metrics. FirstEnergy will continue to review and may refine or change the financial plan in the future as circumstances evolve.

Operational Matters

Transmission Update

JCP&L has proposed to build a new 230 kV transmission line in Monmouth County, New Jersey to add redundancy to the system and meet the growing demand for electricity. The project, known as Oceanview Reinforcement Project, is expected to be built between the existing Larrabee Substation in Howell and the existing Oceanview Substation in Neptune. The project is part of the JCP&L LITE Program, a $200 million, multi-year comprehensive reliability plan.

Employee Relations

FirstEnergy is engaged in negotiations with UWUA Local 102 which represents approximately 950 employees at WP, PE and AE Supply. The current collective bargaining agreement expired on April 30, 2013. Although the parties continue to bargain, WP, PE and AE Supply have work continuation plans in place in the event of any work stoppage.

FirstEnergy is engaged in negotiations with UWUA Local 180 which represents approximately 150 employees at PN. The current collective bargaining agreement will expire on August 31, 2013. The parties are currently negotiating and, in the event of a work stoppage, a work continuation plan is in place.

Regulatory Matters

JCP&L Rate Filing Update

On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where a recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding.

FIRSTENERGY’S BUSINESS

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 in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). 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 derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, 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 approximately 18,000 MWs of capacity (including 885 MWs of capacity subject to RMR arrangements with PJM and 2,080 MWs of capacity planned to be deactivated by October 9, 2013) and also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment 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 demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment 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.

The Competitive Energy Services 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. As of June 30, 2013, the percentage of expected physical sales economically hedged was 103% for 2013 (of a 104 million MWH target).

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 14, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various commodity vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

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 14, Segment Information, of the Combined Notes to Consolidated Financial Statements. Net income by business segment was as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	2013	2012	Increase (Decrease)	2013	2012	Increase (Decrease)
	(In millions, except per share)					
Earnings (Losses) By Business Segment:						
Regulated Distribution	$179	$158	$21	$389	$317	$72
Regulated Transmission	51	54	(3)	102	112	(10)
Competitive Energy Services	(339)	25	(364)	(377)	166	(543)
Other and reconciling adjustments [1]	(55)	(50)	(5)	(82)	(102)	20
Net Income (Loss)	$(164)	$187	$(351)	$32	$493	$(461)
Basic Earnings (Losses) Per Share	$(0.39)	$0.45	$(0.84)	$0.08	$1.18	$(1.10)
Diluted Earnings (Losses) Per Share	$(0.39)	$0.45	$(0.84)	$0.08	$1.18	$(1.10)

(1) Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses and the elimination of intersegment transactions.

62

Summary of Results of Operations — Second Quarter 2013 Compared with Second Quarter 2012

Financial results for FirstEnergy's business segments in the second quarter of 2013 and 2012 were as follows:

Second Quarter 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$1,977	$180	$1,331	$(42)	$3,446
Other	64	—	46	(37)	73
Internal	—	—	176	(176)	—
Total Revenues	2,041	180	1,553	(255)	3,519
Operating Expenses:					
Fuel	75	—	553	—	628
Purchased power	762	—	276	(176)	862
Other operating expenses	402	33	534	(82)	887
Provision for depreciation	151	28	114	9	302
Amortization of regulatory assets, net	69	3	—	—	72
General taxes	172	14	50	5	241
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	1,631	78	2,000	(244)	3,465
Operating Income (Loss)	410	102	(447)	(11)	54
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(32)	8	(24)
Investment income (loss)	9	—	(17)	(7)	(15)
Interest expense	(135)	(22)	(61)	(38)	(256)
Capitalized interest	3	1	11	4	19
Total Other Expense	(123)	(21)	(99)	(33)	(276)
Income (Loss) Before Income Taxes	287	81	(546)	(44)	(222)
Income taxes (benefits)	108	30	(207)	11	(58)
Net Income (Loss)	179	51	(339)	(55)	(164)
Income attributable to noncontrolling interest	—	—	—	—	—
Earnings (Losses) Available to FirstEnergy Corp.	$179	$51	$(339)	$(55)	$(164)

Second Quarter 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,088	$184	$1,454	$(59)	$3,667
Other	51	—	47	(10)	88
Internal	—	—	209	(209)	—
Total Revenues	2,139	184	1,710	(278)	3,755
Operating Expenses:					
Fuel	58	—	598	—	656
Purchased power	895	—	355	(208)	1,042
Other operating expenses	446	41	513	(79)	921
Provision for depreciation	145	29	103	8	285
Amortization of regulatory assets, net	63	—	—	(1)	62
General taxes	166	9	49	8	232
Total Operating Expenses	1,773	79	1,618	(272)	3,198
Operating Income	366	105	92	(6)	557
Other Income (Expense):					
Investment income	19	1	6	(13)	13
Interest expense	(135)	(23)	(71)	(45)	(274)
Capitalized interest	2	1	12	4	19
Total Other Expense	(114)	(21)	(53)	(54)	(242)
Income Before Income Taxes	252	84	39	(60)	315
Income taxes	94	30	14	(11)	127
Net Income	158	54	25	(49)	188
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$158	$54	$25	$(50)	$187

Changes Between Second Quarter 2013 and Second Quarter 2012 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(111)	$(4)	$(123)	$17	$(221)
Other	13	—	(1)	(27)	(15)
Internal	—	—	(33)	33	—
Total Revenues	(98)	(4)	(157)	23	(236)
Operating Expenses:					
Fuel	17	—	(45)	—	(28)
Purchased power	(133)	—	(79)	32	(180)
Other operating expenses	(44)	(8)	21	(3)	(34)
Provision for depreciation	6	(1)	11	1	17
Amortization of regulatory assets, net	6	3	—	1	10
General taxes	6	5	1	(3)	9
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	(142)	(1)	382	28	267
Operating Income (Loss)	44	(3)	(539)	(5)	(503)
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(32)	8	(24)
Investment income (loss)	(10)	(1)	(23)	6	(28)
Interest expense	—	1	10	7	18
Capitalized interest	1	—	(1)	—	—
Total Other Expense	(9)	—	(46)	21	(34)
Income (Loss) Before Income Taxes	35	(3)	(585)	16	(537)
Income taxes (benefits)	14	—	(221)	22	(185)
Net Income (Loss)	21	(3)	(364)	(6)	(352)
Income (loss) attributable to noncontrolling interest	—	—	—	(1)	(1)
Earnings (Losses) Available to FirstEnergy Corp.	$21	$(3)	$(364)	$(5)	$(351)

Regulated Distribution — Second Quarter 2013 Compared with Second Quarter 2012

Net income increased by $21 million in the second quarter of 2013 compared to the same period of 2012, primarily due to higher residential distribution revenue and lower operating and maintenance expenses.

Revenues —

The $98 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Distribution services	$897	$934	$(37)
Generation sales:			
Retail	917	961	(44)
Wholesale	61	86	(25)
Total generation sales	978	1,047	(69)
Transmission	102	107	(5)
Other	64	51	13
Total Revenues	$2,041	$2,139	$(98)

The decrease in distribution services revenue is primarily related to a decrease in the ME and PN NUG riders which resulted from the expiration of three NUG agreements, partially offset by higher residential electric distribution MWH deliveries (described below) and an increase in the Ohio Companies' DCR rider. Distribution deliveries decreased by 0.9% in the second quarter of 2013 compared to the same period of 2012. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended June 30 2013	2012	Increase (Decrease)
	(In thousands)		
Residential	12,128	11,832	2.5 %
Commercial	10,241	10,564	(3.1)%
Industrial	12,495	12,784	(2.3)%
Other	142	151	(6.0)%
Total Electric Distribution MWH Deliveries	35,006	35,331	(0.9)%

Higher deliveries to residential customers primarily reflects increased weather-related usage resulting from heating degree days that were 15% above 2012 levels, but 5% below normal, partially offset by cooling degree days that were 13% below 2012, but 12% above normal. Lower deliveries to the commercial sector primarily reflect increasing energy efficiency mandates and demand response initiatives. In the Industrial sector, decreased sales to steel and automotive customers, were partially offset by higher sales to chemical and petroleum customers. For 2013, we continue to expect an overall increase in industrial sales, with a majority of that increase resulting from shale gas activities.

The following table summarizes the price and volume factors contributing to the $69 million decrease in generation revenues for the second quarter of 2013 compared to the same period of 2012:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(47)
Change in prices	3
	(44)
Wholesale:	
Effect of decrease in sales volumes	(34)
Change in prices	9
	(25)
Decrease in Generation Revenues	$(69)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during the second quarter of 2013, compared to the same period of 2012. This increased customer shopping, which does not impact earnings for the Regulated Segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 79% for the Ohio Companies, 67% from 65% for the Pennsylvania Companies and 54% from 51% for JCP&L.

The decrease in wholesale generation revenues of $25 million in the second quarter of 2013 resulted from the expiration of NUG contracts in 2012 and 2013.

Other revenues increased by $13 million primarily due to more customer requested work in the second quarter of 2013 compared to the same period of 2012.

Operating Expenses —

Total operating expenses decreased by $142 million primarily due to the following:

- Fuel expense was $17 million higher in 2013 primarily related to increased generation at Fort Martin as a result of a planned outage in the second quarter of 2012 to perform routine maintenance work.

- Purchased power costs were $133 million lower in 2013 primarily due to a decrease in volumes required due to increased customer shopping, higher generation at Fort Martin, reduced NUG cost associated with the expiration of NUG contracts and lower unit power supply costs during the second quarter of 2013 compared to the same period of 2012.

Source of Change in Purchased Power	Increase(Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (43)
Change due to decreased volumes	(101)
	(144)
Purchases from affiliates:	
Change due to decreased unit costs	(5)
Change due to decreased volumes	(23)

	(28)
Decrease in costs deferred	39
Net Decrease in Purchased Power Costs	$ (133)

67

- Other operating expenses decreased $44 million primarily due to:

- a decrease in energy efficiency program expenses of $12 million resulting from the completion of phase 1 initiatives in Ohio and Pennsylvania, which are recovered through rates,

- lower distribution operating and maintenance expenses of $20 million primarily due to a greater focus on capital work and cost savings initiatives, including staffing reductions and benefit plan changes, implemented subsequent to the second quarter of 2012, as well as lower storm related maintenance activities during the second quarter of 2013,

- decreased regulated generation operating and maintenance expenses of $10 million primarily related to a planned outage at Fort Martin in the second quarter of 2012 to perform routine maintenance work and the elimination of costs associated with certain deactivated units,

- Depreciation expense increased by $6 million due to a higher asset base, partially offset by a reduction in depreciation rates for WP that was approved by the PPUC in September 2012.

- Net regulatory asset amortization increased $6 million primarily due to higher Pennsylvania Companies' default generation service cost recovery and decreases in deferred storm costs and energy efficiency program costs, partially offset by a reduction in NUG cost recovery at ME and PN.

- General taxes increased by $6 million primarily due to higher property taxes, partially offset by a decrease in gross receipts taxes.

Other Expense —

Other expense increased $9 million in the second quarter of 2013 primarily due to lower investment income resulting from the liquidation of investments at Shippingport and higher OTTI on the NDT investments of OE and TE.

Regulated Transmission — Second Quarter 2013 Compared with Second Quarter 2012

Net income decreased by $3 million in the second quarter of 2013 compared to the same period of 2012 primarily due to lower revenues in the second quarter of 2013.

Revenues —

Total revenues decreased by $4 million principally due to lower PJM network service revenues for ATSI and the Utilities.

Revenues by transmission asset owner are shown in the following table:

	Three Months Ended June 30		Increase
Revenues by Transmission Asset Owner	2013	2012	(Decrease)
	(In millions)		
ATSI	$51	$54	$(3)
TrAIL	51	49	2
PATH	5	4	1
Utilities	73	77	(4)
Total Revenues	$180	$184	$(4)

Operating Expenses —

Total operating expenses decreased by $1 million principally due to lower transmission operating and maintenance expenses due to a greater focus on capital work and previously implemented cost savings initiatives, partially offset by higher property taxes.

Competitive Energy Services — Second Quarter 2013 Compared with Second Quarter 2012

Net income decreased by $364 million in the second quarter of 2013, compared to the same period of 2012. The decrease in net income was primarily due to a pre-tax impairment of $473 million on long-lived assets, loss on debt redemptions and lower wholesale sales revenues, partially offset by increased governmental aggregation sales and lower operating expenses.

Revenues —

Total revenues decreased by $157 million in the second quarter of 2013, compared to the same period of 2012, primarily due to a decline in wholesale sales. Revenues were also adversely impacted by lower unit prices compared to 2012. These decreases were partially offset by growth in governmental aggregation and mass market sales.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Direct	$725	$756	$(31)
Governmental Aggregation	273	223	50
Mass Market	99	76	23
POLR and Structured	282	295	(13)
Wholesale	94	271	(177)
Transmission	34	42	(8)
Other	46	47	(1)
Total Revenues	$1,553	$1,710	$(157)

MWH Sales by Channel	Three Months Ended June 30 2013	2012	Increase (Decrease)
	(In thousands)		
Direct	14,008	13,937	0.5%
Governmental Aggregation	4,776	3,638	31.3%
Mass Market	1,491	1,106	34.8%
POLR and Structured	5,541	5,379	3.0%
Wholesale	599	2,055	(70.9)%
Total MWH Sales	26,415	26,115	1.1%

The decrease in Direct revenues of $31 million resulted from lower unit prices in all customer classes while sales volumes increased slightly due to the acquisition of new customers. The increase in Governmental Aggregation of $50 million resulted from the acquisition of new customers primarily in Illinois, partially offset by lower unit prices. The increase in Mass Market of $23 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of June 30, 2013 as compared to 2.0 million as of June 30, 2012.

The decrease in POLR and structured revenues of $13 million was due primarily to lower prices and lower POLR sales, partially offset by higher structured sales. The decline in POLR sales is in line with FES' strategy to realign its sales portfolio.

Wholesale revenues decreased $177 million due to a $82 million reduction in gains on financially settled contracts, a $62 million decrease in capacity revenues primarily from lower capacity prices and a $33 million decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale, primarily as a result of the plants that were deactivated in 2012 and those under RMR arrangements and higher retail sales volumes.

The following tables summarize the price and volume factors contributing to changes in revenues:

Source of Change in Direct Revenues	Increase (Decrease) (In millions)
Direct :	
Effect of increase in sales volumes	$4
Change in prices	(35)
	$(31)

Source of Change in Governmental Aggregation Revenues	Increase (Decrease) (In millions)
Governmental Aggregation:	
Effect of increase in sales volumes	$69
Change in prices	(19)
	$50

Source of Change in Mass Market Revenues	Increase (Decrease) (In millions)
Mass Market:	
Effect of increase in sales volumes	$27
Change in prices	(4)
	$23

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
POLR and Structured:	
Effect of increase in sales volumes	$5
Change in prices	(18)
	$(13)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(37)
Change in prices	4
Gain on settled contracts	(82)
Capacity revenue	(62)
	$(177)

Operating Expenses —

Total operating expenses increased by $382 million in the second quarter of 2013 due to the following:

- Fuel costs decreased $45 million due to lower unit prices ($15 million), resulting from new and restructured coal contracts, partially offset by settlements associated with past damages on various coal and transportation contracts, and lower volumes consumed ($30 million). Volumes decreased as a result of lower fossil generation primarily from the plants that were deactivated in 2012 and those under RMR arrangements and lower nuclear generation.

- Purchased power costs decreased $79 million due to reduced capacity expenses ($78 million), lower losses on financially settled contracts ($103 million), partially offset by higher volumes ($74 million) and increased prices ($28 million). The increase in purchased power volumes relates to lower generation primarily from the plants that were deactivated in 2012 and those under RMR arrangements, and the overall increase in sales volumes.
- Fossil operating costs decreased by $18 million due primarily to lower labor costs resulting from previously deactivated units.
- Nuclear operating costs decreased by $32 million due primarily to lower contractor, materials and equipment costs. In 2013, there was a single refueling outage at Perry while there were two refueling outages during the second quarter of 2012.
- Transmission expenses increased $18 million due primarily to higher ancillary, network and line loss costs associated with additional retail load, partially offset by lower congestion costs.
- General taxes increased by $1 million due primarily to higher property taxes.
- Impairments of long-lived assets increased by $473 million due to the decision to deactivate two unregulated, coal-fired generating plants.
- Depreciation expense increased $11 million primarily due to a higher asset base.
- Other operating expenses increased by $53 million primarily due to an increase in mark-to-market expense on commodity contract positions ($35 million), increased severance benefits related to plant deactivation ($16 million) and higher retail expenses ($9 million), partially offset by reduced lease costs from the sale and leaseback repurchases ($7 million).

Other Expense —

Total other expense in the second quarter of 2013 increased $46 million compared to the same period of 2012 primarily due to a $32 million loss on debt redemption in connection with senior notes that were repurchased, lower investment income of $23 million due to higher OTTI on the NDT investments, partially offset by lower net interest expense of $9 million due to debt redemptions and repurchases.

Other — Second Quarter 2013 Compared with Second Quarter 2012

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $6 million decrease in net income in the second quarter of 2013 compared to the same period of 2012 primarily due to the recognition of valuation reserves against certain NOLs resulting from the decision to deactivate two unregulated coal-fired generating plants, partially offset by gains from fair value hedges associated with the redemptions of long-term debt and reduced interest expense.

Summary of Results of Operations — First Six Months of 2013 Compared with the First Six Months of 2012

Financial results for FirstEnergy's business segments in the first six months of 2013 and 2012 were as follows:

First Six Months 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,130	$356	$2,710	$(93)	$7,103
Other	123	—	81	(59)	145
Internal	—	—	392	(392)	—
Total Revenues	4,253	356	3,183	(544)	7,248
Operating Expenses:					
Fuel	162	—	1,096	—	1,258
Purchased power	1,637	—	560	(392)	1,805
Other operating expenses	817	63	1,063	(172)	1,771
Provision for depreciation	295	56	225	20	596
Amortization of regulatory assets, net	127	4	—	—	131
General taxes	354	26	110	16	506
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	3,392	149	3,527	(528)	6,540
Operating Income (Loss)	861	207	(344)	(16)	708
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	8	(141)
Investment income (loss)	27	—	(1)	(23)	3
Interest expense	(270)	(45)	(134)	(65)	(514)
Capitalized interest	5	1	21	7	34
Total Other Expense	(238)	(44)	(263)	(73)	(618)
Income (Loss) Before Income Taxes	623	163	(607)	(89)	90
Income taxes (benefits)	234	61	(230)	(7)	58
Net Income (Loss)	389	102	(377)	(82)	32
Income attributable to noncontrolling interest	—	—	—	—	—
Earnings (Losses) Available to FirstEnergy Corp.	$389	$102	$(377)	$(82)	$32

First Six Months 2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,392	$370	$2,944	$(111)	$7,595
Other	101	—	76	(29)	148
Internal	—	—	477	(475)	2
Total Revenues	4,493	370	3,497	(615)	7,745
Operating Expenses:					
Fuel	97	—	1,100	—	1,197
Purchased power	1,977	—	798	(474)	2,301
Other operating expenses	912	69	922	(164)	1,739
Provision for depreciation	287	58	203	16	564
Amortization of regulatory assets, net	138	—	—	(1)	137
General taxes	356	21	110	17	504
Total Operating Expenses	3,767	148	3,133	(606)	6,442
Operating Income	726	222	364	(9)	1,303
Other Income (Expense):					
Investment income	42	1	12	(31)	24
Interest expense	(269)	(46)	(136)	(69)	(520)
Capitalized interest	5	1	23	7	36
Total Other Expense	(222)	(44)	(101)	(93)	(460)
Income Before Income Taxes	504	178	263	(102)	843
Income taxes	187	66	97	(1)	349
Net Income	317	112	166	(101)	494
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings (Losses) Available to FirstEnergy Corp.	$317	$112	$166	$(102)	$493

Changes Between First Six Months 2013 and First Six Months 2012 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(262)	$(14)	$(234)	$18	$(492)
Other	22	—	5	(30)	(3)
Internal	—	—	(85)	83	(2)
Total Revenues	(240)	(14)	(314)	71	(497)
Operating Expenses:					
Fuel	65	—	(4)	—	61
Purchased power	(340)	—	(238)	82	(496)
Other operating expenses	(95)	(6)	141	(8)	32
Provision for depreciation	8	(2)	22	4	32
Amortization of regulatory assets, net	(11)	4	—	1	(6)
General taxes	(2)	5	—	(1)	2
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	(375)	1	394	78	98
Operating Income (Loss)	135	(15)	(708)	(7)	(595)
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	8	(141)
Investment income	(15)	(1)	(13)	8	(21)
Interest expense	(1)	1	2	4	6
Capitalized interest	—	—	(2)	—	(2)
Total Other Expense	(16)	—	(162)	20	(158)
Income (Loss) Before Income Taxes	119	(15)	(870)	13	(753)
Income taxes (benefits)	47	(5)	(327)	(6)	(291)
Net Income (Loss)	72	(10)	(543)	19	(462)
Loss attributable to noncontrolling interest	—	—	—	(1)	(1)
Earnings (Losses) Available to FirstEnergy Corp.	$72	$(10)	$(543)	$20	$(461)

Regulated Distribution — First Six Months of 2013 Compared with First Six Months of 2012

Net income increased by $72 million in the first six months of 2013 compared to the same period of 2012, primarily due to higher residential distribution revenue and lower operating and maintenance expenses.

Revenues —

The $240 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Distribution services	$1,868	$1,884	$(16)
Generation sales:			
Retail	1,922	2,104	(182)
Wholesale	122	183	(61)
Total generation sales	2,044	2,287	(243)
Transmission	218	221	(3)
Other	123	101	22
Total Revenues	$4,253	$4,493	$(240)

The decrease in distribution services revenue is primarily the result of a NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, and a decrease to the ME and PN NUG riders which resulted from the expiration of three NUG agreements, partially offset by higher residential electric distribution MWH deliveries (described below) and an increase in the Ohio Companies' DCR rider. Distribution deliveries increased by 0.9% in the first six months of 2013 compared to the same period of 2012. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In thousands)		
Residential	27,084	25,926	4.5 %
Commercial	20,690	20,948	(1.2)%
Industrial	25,119	25,355	(0.9)%
Other	290	297	(2.4)%
Total Electric Distribution MWH Deliveries	73,183	72,526	0.9 %

Higher deliveries to residential customers primarily reflect increased weather-related usage resulting from heating degree days that were 27% above 2012 levels, partially offset by cooling degree days that were 16% lower than 2012 levels. Lower deliveries to the commercial sector primarily reflect increasing energy efficiency mandates and demand response initiatives. In the Industrial sector, decreased sales to steel and automotive customers were partially offset by higher sales to chemical and petroleum customers.

The following table summarizes the price and volume factors contributing to the $243 million decrease in generation revenues for the first six months of 2013 compared to the same period of 2012:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(97)
Change in prices	(85)
	(182)
Wholesale:	
Effect of decrease in sales volumes	(64)
Change in prices	3
	(61)
Decrease in Generation Revenues	$(243)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during the first six months of 2013, compared to the same period of 2012. This increased customer shopping, which does not impact earnings for the Regulated Segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 80% from 78% for the Ohio Companies, 65% from 61% for the Pennsylvania Companies and 53% from 50% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices for power supply in the first six months of 2013 compared to the same period of 2012.

The decrease in wholesale generation revenues of $61 million in the first six months of 2013 resulted from the expiration of NUG contracts in 2012 and 2013.

Other revenues increased by $22 million primarily due to more customer requested work in the first six months of 2013 compared to the same period of 2012.

Operating Expenses —

Total operating expenses decreased by $375 million due to the following:

- Fuel expense was $65 million higher in 2013 primarily related to increased generation at Fort Martin as a result of a planned outage in the first and second quarter of 2012 to perform routine maintenance work.
- Purchased power costs were $340 million lower in 2013 primarily due to a decrease in volumes required from increased customer shopping, higher generation at Fort Martin, reduced NUG cost associated with the expiration of NUG contracts and lower unit power supply costs during the first six months of 2013 compared to the same period of 2012, partially offset by higher weather-related usage.

Source of Change in Purchased Power	Increase(Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (113)
Change due to decreased volumes	(208)
	(321)
Purchases from affiliates:	

Change due to decreased unit costs	(41)
Change due to decreased volumes	(32)
	(73)
Decrease in costs deferred	54
Net Decrease in Purchased Power Costs	$ (340)

76

- Other operating expenses decreased $95 million primarily due to:

- a decrease in energy efficiency program expenses of $39 million resulting from the completion of phase 1 initiatives in Ohio and Pennsylvania, which are recovered through rates,

- lower distribution operating and maintenance expenses of $47 million primarily due to a greater focus on capital work and cost savings initiatives, including staffing reductions and benefit plan changes, implemented subsequent to the second quarter of 2012, as well as lower storm related maintenance activities during the first six months of 2013,

- decreased regulated generation operating and maintenance expenses of $16 million primarily related to a planned outage at Fort Martin in the first and second quarter of 2012 to perform routine maintenance work and the elimination of costs associated with certain deactivated units,

- transmission expenses that increased by $10 million primarily due to PJM charges to the Ohio Companies, which are recovered through the NMB transmission rider discussed above.

- Depreciation expense increased by $8 million due to a higher asset base, partially offset by a reduction in depreciation rates for WP that was approved by the PPUC in September 2012.

- Net regulatory asset amortization decreased $11 million primarily due to a reduction in NUG cost recovery at JCP&L, ME and PN, partially offset by decreases in the storm cost deferral and deferred energy efficiency program costs.

- General taxes decreased by $2 million primarily due to a decrease in gross receipt taxes, payroll taxes and West Virginia's business and occupation tax, partially offset by an increase in property taxes.

Other Expense —

Other expense increased $16 million in the first six months of 2013 primarily due to lower investment income resulting from the liquidation of investments at Shippingport and higher OTTI on the NDT of OE and TE.

Regulated Transmission — First Six Months of 2013 Compared with First Six Months of 2012

Net income decreased by $10 million in the first six months of 2013 compared to the same period of 2012 primarily due to lower revenues in the first six months of 2013 compared to 2012.

Revenues —

Total revenues decreased by $14 million principally due to lower PJM network service revenues for ATSI and the Utilities and a lower rate base for TrAIL.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
ATSI	$100	$107	$(7)
TrAIL	99	102	(3)
PATH	10	7	3
Utilities	147	154	(7)
Total Revenues	$356	$370	$(14)

Operating Expenses —

Total operating expenses increased by $1 million principally due to higher property taxes, partially offset by lower transmission operating and maintenance expenses due to a greater focus on capital work and previously implemented cost savings initiatives.

Competitive Energy Services — First Six Months of 2013 Compared with First Six Months of 2012

Net income decreased by $543 million in the first six months of 2013, compared to the same period of 2012. The decrease in net income was primarily due to a pre-tax impairment of $473 million on long-lived assets, a loss on debt redemptions and lower wholesale sales revenues, partially offset by increased governmental aggregation sales and lower operating expenses.

Revenues —

Total revenues decreased by $314 million in the first six months of 2013, compared to the same period of 2012, primarily due to a decline in wholesale sales. Revenues were also adversely impacted by lower unit prices compared to 2012. These decreases were partially offset by growth in governmental aggregation and mass market sales.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Direct	$1,435	$1,461	$(26)
Governmental Aggregation	565	466	99
Mass Market	216	159	57
POLR and Structured	633	674	(41)
Wholesale	171	568	(397)
Transmission	82	88	(6)
RECs	—	5	(5)
Other	81	76	5
Total Revenues	$3,183	$3,497	$(314)

MWH Sales by Channel	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In thousands)		
Direct	27,621	26,716	3.4 %
Governmental Aggregation	10,162	7,604	33.6 %
Mass Market	3,271	2,326	40.6 %
POLR and Structured	12,358	12,022	2.8 %
Wholesale	831	2,766	(70.0)%
Total MWH Sales	54,243	51,434	5.5 %

The decrease in Direct revenues of $26 million resulted from lower unit prices in all customer classes. Sales volumes increased due to the acquisition of new customers and weather related usage as heating degree days were 27% above 2012 levels, partially offset by cooling degree days which were 16% below 2012 levels. The increase in Governmental Aggregation of $99 million resulted from the acquisition of new customers primarily in Illinois and weather related usage partially offset by lower unit prices. The increase in Mass Market of $57 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania and weather related usage partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of June 30, 2013 as compared to 2.0 million as of June 30, 2012.

The decrease in POLR and structured revenues of $41 million was due primarily to lower prices and lower POLR sales, partially offset by higher structured sales. The decline in POLR sales is in line with FES' strategy to realign its sales portfolio.

Wholesale revenues decreased $397 million due to a $175 million reduction in gains on financially settled contracts, a $175 million decrease in capacity revenues primarily from lower capacity prices and a $47 million decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale, primarily as a result of the plants that were deactivated in 2012 and those under RMR arrangements and higher retail sales volumes.

The following tables summarize the price and volume factors contributing to changes in revenues:

Source of Change in Direct Revenues	Increase (Decrease) (In millions)
Direct :	
Effect of increase in sales volumes	$49
Change in prices	(75)
	$(26)

Source of Change in Governmental Aggregation Revenues	Increase (Decrease) (In millions)
Governmental Aggregation:	
Effect of increase in sales volumes	$156
Change in prices	(57)
	$99

Source of Change in Mass Market Revenues	Increase (Decrease) (In millions)
Mass Market:	
Effect of increase in sales volumes	$65
Change in prices	(8)
	$57

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
POLR and Structured:	
Effect of increase in sales volumes	$18
Change in prices	(59)
	$(41)

Source of Change in Wholesale Revenues	Increase (Decrease) (In millions)
Wholesale:	
Effect of decrease in sales volumes	$(51)
Change in prices	4
Gain on settled contracts	(175)
Capacity revenue	(175)
	$(397)

Operating Expenses —

Total operating expenses increased by $394 million in the first six months of 2013 due to the following:

- Fuel costs decreased $4 million due to lower volumes consumed ($9 million) and lower unit prices associated with new and restructured coal contracts, partially offset by settlements associated with past damages on various coal and transportation contracts. Volumes decreased as a result of lower fossil generation primarily from the plants that were deactivated in 2012 and those under RMR arrangements and lower nuclear generation.

79

- Purchased power costs decreased $238 million due to reduced capacity expenses ($214 million), lower losses on financially settled contracts ($208 million), partially offset by higher volumes ($149 million) and prices ($35 million). The increase in purchased power volumes relates to lower generation primarily from the plants that were deactivated in 2012 and those under RMR arrangements, and the overall increase in sales volumes.
- Fossil operating costs decreased by $11 million due primarily to lower labor costs resulting from previously deactivated units. The lower labor costs were partially offset by higher contractor, materials and equipment costs resulting from an increase in planned generating unit outages in the first six months of 2013 as compared to the same period in 2012.
- Nuclear operating costs decreased by $18 million due primarily to lower contractor, materials and equipment costs. In 2013, there was a single refueling outage at Perry while there were two refueling outages during the same period of 2012.
- Transmission expenses increased $59 million due primarily to higher ancillary, network and line loss costs associated with additional retail load, partially offset by lower congestion costs.
- Impairments of long-lived assets increased by $473 million due to the decision to deactivate two unregulated, coal-fired generating plants.
- Depreciation expense increased $22 million primarily due to the absence of credits in 2013 from a 2012 settlement with the DOE and a higher asset base.
- Other operating expenses increased by $111 million primarily due to an increase in mark-to-market expense on commodity contract positions ($101 million), increased severance benefits related to planned plant deactivations ($16 million) and higher retail expenses ($15 million), partially offset by reduced lease costs from the sale and leaseback repurchases ($21 million).

Other Expense —

Total other expense in the first six months of 2013 increased $162 million compared to the same period of 2012 primarily due to a $149 million loss on debt redemptions in connection with senior notes that were repurchased and lower investment income of $13 million due to higher OTTI on NDT investments.

Other — First Six Months of 2013 Compared with First Six Months of 2012

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $19 million increase in net income in the first six months of 2013 compared to the same period of 2012 due to lower income tax expense incurred resulting from a change in state income tax allocation factors, gains from hedges associated with debt redemptions and reduced interest expense, partially offset by the recognition of valuation reserves against certain NOLs resulting from the decision to deactivate two unregulated coal-fired generating plants.

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 June 30, 2013 and December 31, 2012, and the changes during the six months ended June 30, 2013:

Regulatory Assets by Source	June 30, 2013	December 31, 2012	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$256	$293	$(37)
Customer receivables for future income taxes	501	508	(7)
Nuclear decommissioning and spent fuel disposal costs	(199)	(219)	20

Asset removal costs	(355)	(372)	17
Deferred transmission costs	393	390	3
Deferred generation costs	429	379	50
Deferred distribution costs	213	231	(18)
Contract valuations	450	463	(13)
Storm-related costs	458	469	(11)
Other	175	233	(58)
Total	$2,321	$2,375	$(54)

Regulatory assets that do not earn a current return totaled approximately $628 million as of June 30, 2013 of which $439 million represents storm damage costs and $189 million represents PJM transmission and regulatory transition costs that are expected to be recovered by 2020.

As of June 30, 2013 and December 31, 2012, FirstEnergy had approximately $375 million and $392 million, respectively, 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 and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2013 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.

As discussed in the Overview, FirstEnergy's 2013 financial plan also includes a series of actions, including the net transfer of 1,476 MW between AE Supply and MP of the Harrison and Pleasants power plants, and the proposed sale of up to 1,240 MW of unregulated hydro assets. In March, the WVPSC adopted a procedural schedule for the Harrison/Pleasants asset transfer, and hearings were held in May 2013. FirstEnergy expects this regulatory process to be completed during the third quarter of 2013. Proceeds from both of these transactions are expected to be used to further reduce debt at the Competitive Energy Services segment. FirstEnergy also anticipates refinancing maturing debt at certain Utilities and reducing short-term borrowings. Instead of issuing a modest amount of equity in a new capital raising transaction or program, FirstEnergy expects to begin fulfilling certain share-based benefit plan and dividend reinvestment obligations through the issuance of authorized but unissued equity as opposed to its current practice of purchasing shares in the open market. FirstEnergy now believes that additional equity will not be necessary to support the 2013 financial plan. Accordingly, no additional issuances of equity are planned.

Because the activities contemplated by the 2013 financial plan are subject to market conditions and other factors, no assurance can be given that FirstEnergy will complete all of the remaining components of its 2013 financial plan or that the regulatory approvals for the asset transfers will be obtained, any hydro assets will be sold or additional FE equity will be issued within the currently expected timeframes or at all. In addition, FirstEnergy expects to consider changes or additions to the 2013 financial plan from time to time.

As of June 30, 2013, 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 June 30, 2013, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs [(1)]	$809
Unsecured notes	907
Unsecured PCRBs [(1)]	50
Collateralized lease obligation bonds	67
Sinking fund requirements	88
Other notes	31
	$1,952

(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

FirstEnergy had $3,254 million of short-term borrowings as of June 30, 2013, and $1,969 million as of December 31, 2012. FirstEnergy's available liquidity as of July 31, 2013, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	May 2018	$2,500	$268
FES / AE Supply	Revolving	May 2018	2,500	2,499
FET[2]	Revolving	May 2018	1,000	—
AGC	Revolving	Dec. 2013	50	30
		Subtotal	$6,050	$2,797
		Cash	—	189
		Total	$6,050	$2,986

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. 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 of no more than 65%, and 70% 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 well as the debt to total capitalization ratios (as defined under each of the Facilities) as of June 30, 2013:

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		Debt to Capitalization	
	(In millions)						
FE	$2,500	$—	$—	$—	(1)	62.0	%
FES	—	1,500	—	—	(2)	37.2	%
AE Supply	—	1,500	—	—	(2)	33.8	%
FET	—	—	1,000	—	(1)	65.4	%
OE	500	—	—	500	(3)	57.6	%
CEI	500	—	—	500	(3)	58.7	%
TE	500	—	—	500	(3)	61.1	%
JCP&L	600	—	—	850	(3)	50.1	%
ME	300	—	—	500	(3)	54.5	%
PN	300	—	—	300	(3)	56.4	%
WP	200	—	—	200	(3)	50.8	%
MP	150	—	—	150	(3)	51.6	%
PE	150	—	—	150	(3)	53.0	%
ATSI	—	—	100	100	(3)	51.4	%
Penn	50	—	—	50	(3)	40.6	%
TrAIL	—	—	200	400	(3)	45.0	%

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy 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.

On May 8, 2013, FE, FES, and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

AGC Revolving Credit Facility

A separate $50 million revolving credit facility is available to AGC until December 2013. Under the terms of this credit facility, outstanding debt of AGC may not exceed 65% of the sum of its debt and equity as of the last day of each calendar quarter. This provision limits the debt level of AGC and also limits the net assets of AGC that may be transferred to AE. As of June 30, 2013, the debt to total capitalization ratio for AGC (as defined under this credit facility) was 45%.

FirstEnergy Money Pools

FirstEnergy’s regulated 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 the first six months of 2013 was 0.49% per annum for the regulated companies’ money pool and 1.30% per annum for the unregulated companies’ money pool.

Pollution Control Revenue Bonds

As of June 30, 2013, FirstEnergy’s currently payable long-term debt included approximately $809 million ($736 million applicable to FES) of 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 June 30, 2013 were issued by the following banks:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
UBS	$268	April 2014	April 2014
CitiBank N.A.	164	June 2014	June 2014
Wells Fargo	151	March 2014	March 2014
The Bank of Nova Scotia	48	April 2014	Multiple dates[2]
The Bank of Nova Scotia	82	April 2015	April 2015
The Bank of Nova Scotia	96	December 2015	December 2015
Total	$809		

(1) Excludes approximately $9 million of applicable interest coverage.
(2) Earlier of 6 months from drawing or the LOC termination date.

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 July 31, 2013:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BB+
FES	—	—	—	BBB-	Baa3	BB+
AE Supply	—	—	—	BBB-	Baa3	BB+
AGC	—	—	—	BBB-	Baa3	BBB
ATSI	—	—	—	BBB-	Baa2	BBB+
CEI	BBB	Baa1	BBB	BBB-	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	BBB	A3	A-	BBB-	Baa2	BBB+
MP	BBB+	Baa1	A-	BBB-	Baa3	BBB+
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
PN	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	—	—	—
PE	BBB+	Baa1	A-	BBB-	Baa3	BBB+
TE	BBB	Baa1	BBB	—	—	—
TrAIL	—	—	—	BBB-	Baa1	BBB+
WP	BBB+	A3	A-	BBB-	Baa2	BBB+

On June 10, 2013, Moody's downgraded the senior unsecured credit ratings for ATSI to Baa2 from Baa1 and TrAIL to Baa1 from A3. The rating outlooks for ATSI and TrAIL are stable.

On July 31, 2013, Fitch downgraded the issuer default and senior unsecured credit ratings of FE, FES and AE Supply to BB+ from BBB-. Fitch also downgraded JCP&L's issuer default rating to BBB- from BBB, the senior unsecured credit rating to BBB from
BBB+ and revised its outlook to stable from negative.

Debt capacity is subject to the consolidated debt to total capitalization limits within the Facilities discussed above. As of June 30, 2013, FE's incremental debt capacity under its consolidated debt to total capitalization financial covenant is $2.9 billion. As of June 30, 2013, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $2.9 billion given FE's debt to total capitalization ratio of 62.0%.

Changes in Cash Position

As of June 30, 2013, FirstEnergy had $71 million of cash and cash equivalents compared to $172 million of cash and cash equivalents as of December 31, 2012. As of June 30, 2013 and December 31, 2012, FirstEnergy had approximately $73 million and $62 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy’s consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $493 million during the first six months of 2013 compared with $62 million provided from operating activities during the first six months of 2012, as summarized in the following table:

Operating Cash Flows	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Net income	$32	$494	$(462)
Non-cash charges	1,387	900	487
Pension trust contributions	—	(600)	600
Working capital and other	(926)	(732)	(194)
	$493	$62	$431

85

The $431 million increase in cash from operations is primarily a result of a $600 million pension contribution in 2012 that did not occur in 2013. The increase was partially offset by $194 million more in cash outflows in 2013 from changes in operating assets and liabilities primarily as a result of payments in 2013 associated with 2012 storm restoration activities.

The $487 million increase in non-cash charges is primarily due to the following:

- $473 million increase from impairment of long-lived assets due to the Hatfield's Ferry and Mitchell plant deactivations.
- $141 million increase from the loss on debt redemptions associated with the completion of the FES/AE Supply tender offers and the $400 million FES debt redemption described below.
- $110 million increase from lower deferred purchased power and other costs primarily due to the expiration of certain NUG agreements.
- $47 million increase from higher deferred rents and market lease valuation as a result of increased net amortization of lease expense.
- $304 million decrease in deferred income taxes and investment tax credits. Of the decrease, $156 million was the result of the reversal of deferred income tax liabilities associated with the impairment of Hatfield's Ferry and Mitchell as a result of the decision to deactivate the two plants.

Cash Flows From Financing Activities

In the first six months of 2013, cash provided from financing activities was $976 million compared to $831 million of net cash provided from financing activities during the first six months of 2012. The following table summarizes new debt financing (net of any discounts) and redemptions:

Securities Issued or Redeemed / Repaid	Six Months Ended June 30 2013	2012
	(In millions)	
New Issues		
PCRBs	$—	$82
Senior secured notes	445	—
FMBs	—	100
Unsecured Notes	1,800	—
	$2,245	$182
Redemptions / Repayments		
PCRBs	$(234)	$(82)
Long-term revolving credit	(25)	—
Senior secured notes	(120)	(81)
Unsecured notes	(1,589)	(583)
	$(1,968)	$(746)
Short-term borrowings, net	$1,285	$1,890

During the first quarter of 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

Also during the first quarter of 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million (FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

In June 2013, the SPEs formed by the Ohio Companies issued $445 million of phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71% and pay $30 million of make-whole premiums associated with such redemptions which will also be recovered. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows. In addition, during the second quarter FirstEnergy Corp. completed a $1.5 billion equity contribution to FES.

Cash Flows From Investing Activities

Cash used for investing activities in the first six months of 2013 principally represented cash used for property additions. The following table summarizes investing activities for the first six months of 2013 and the comparable period of 2012:

	Six Months Ended June 30		
Cash Used for Investing Activities	2013	2012	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated distribution	$719	$443	$276
Regulated transmission	186	122	64
Competitive energy services	468	303	165
Other and reconciling adjustments	39	43	(4)
Nuclear fuel	50	90	(40)
Investments	(1)	(49)	48
Other	109	49	60
	$1,570	$1,001	$569

Net cash used for investing activities during the first six months of 2013 increased by $569 million compared to the same period of 2012. The increase was principally due to an increase in property additions primarily from 2012 storm costs, including costs associated with Hurricane Sandy, paid in 2013 ($501 million) and a decrease in proceeds from investments primarily as a result of the liquidation of Shippingport investments, partially offset by a decrease in nuclear fuel procurement costs.

In 2012, FG acquired certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million and in March of 2013, FG acquired the remaining interests for approximately $221 million.

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 June 30, 2013, was approximately $3.9 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$264
LOC (long-term debt) - interest coverage[2]	5
OVEC obligations	300
Other[3]	326
	895
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	69
LOC (long-term debt) - interest coverage[2]	3
FES' guarantee of NG's nuclear property insurance	93
FES' guarantee of FG's sale and leaseback obligations	2,064
Other	11
	2,240
Global Holding facility	350
Surety Bonds	241
LOCs[4]	134
	725
Total Guarantees and Other Assurances	$3,860

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $809 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $136 million for nuclear decommissioning funding assurances, $161 million supporting OE's sale and leaseback arrangements, and $23 million for railcar leases.

(4) Includes $9 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $97 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $28 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 June 30, 2013, FES has posted collateral of $86 million. The Regulated Distribution segment has posted collateral of $17 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 as of June 30, 2013:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$437	$6	$44	$487
BB+/Ba1 Credit Ratings	$489	$6	$58	$553
Full impact of credit contingent contractual obligations	$696	$58	$92	$846

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of June 30, 2013, 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 and AE Supply would be required to post $86 million and $3 million, respectively.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. 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 new facility.

In connection with the new facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the new facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility by December 31, 2013 on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1 through December 31, 2013 and, thereafter, a rate per annum equal to the then current Merrill Lynch High Yield 100 index, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

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 Plant 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 $1.2 billion as of June 30, 2013. 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.

During the second quarter of 2013, in connection with the Perry sale and leaseback arrangement, OE provided notice to return the leased interests in the plant to the owner participants (representing an aggregate of approximately 103 MWs of the 1,268 MWs of total capacity of the Perry Plant) at the expiration of the lease (May 2016) in lieu of extending the lease or buying the interest at the then appraised FMV.

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 8, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of commodity derivative contracts assets and liabilities as of June 30, 2013 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2013	2014	2015	2016	2017	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(8)	$(1)	$—	$—	$—	$—	$(9)
Other external sources[2]	(22)	(30)	(35)	(30)	—	—	(117)
Prices based on models	3	(2)	1	1	(22)	(162)	(181)
Total[3]	$(27)	$(33)	$(34)	$(29)	$(22)	$(162)	$(307)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(390) million in non-hedge derivative contracts that are primarily related to NUG and LCAPP contracts. NUG and LCAPP contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of June 30, 2013, a 10% adverse change in commodity prices would decrease net income by approximately $18 million during the next 12 months.

Equity Price Risk

As of June 30, 2013, the FirstEnergy pension plan assets were approximately 25% in equity securities, 40% in fixed income securities, 25% in absolute return strategies, 6% in real estate, 1% in private equity and 3% in cash and short-term securities. A decline in the value of pension 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 six months ended June 30, 2013, FirstEnergy made no contributions to its qualified pension plans. See Note 4, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of June 30, 2013, approximately 74% of the funds were invested in fixed income securities, 21% of the funds were invested in equity securities and 5% 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 $1,618 million, $457 million and $99 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2013, excluding $4 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $46 million reduction in fair value as of June 30, 2013. 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 or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the three months ended June 30, 2013, approximately $5 million was contributed to FirstEnergy's NDT. On June 18, 2013, FE submitted a revised $125 million parental guaranty for NRC review relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. On this date, FE also submitted to the NRC a revised $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities.

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 specified 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 set-off. 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. FirstEnergy's portfolio of energy contracts has a current weighted average risk rating for energy contract counterparties of BBB (S&P).

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 FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

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 residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired, however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change.

PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. 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.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific

SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC has scheduled a hearing for August 20, 2013, to discuss the reports.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; for selective increased investment in system hardening; for creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order requiring the utilities to submit several reports between March 29 and August 30, 2013, 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 requires 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 continues to respond to the requirements in the order consistent with the schedule set forth therein.

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, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, 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 September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU has transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. The updated filing now represents an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). Hearings are currently scheduled in the rate case for mid-September through mid-November. JCP&L is expected to file its rebuttal testimony on August 7, 2013.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. JCP&L intends to vigorously pursue its position in the base rate case and full recovery of the costs associated with the major storm events of 2011 and 2012 but we cannot predict the outcome of these proceedings.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation 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);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM 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 PJM proceedings. The Ohio Companies have also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their current ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing, which the PUCO granted on September 12, 2012, solely for the purpose of giving the PUCO additional time to consider the issues raised in the applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year extension period at levels established in the existing 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);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan will provide additional provisions, including:

- 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 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.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, the Ohio Companies filed their next three-year portfolio plan for the period January 1, 2013 through December 31, 2015 on July 31, 2012. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO issued an entry on rehearing denying the Ohio Companies' application for rehearing, in part, but authorizing the Ohio Companies' to receive 20% of any revenues obtained from bidding energy efficiency and demand response 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.

Additionally, under SB221, electric utilities and electric service companies in Ohio are required to serve part of their load from renewable energy resources measured by an annually increasing percentage amount. In August and October 2009 and in August 2010, the Ohio Companies conducted RFPs to secure RECs. The RECs acquired through these three RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. In August 2011, the Ohio Companies conducted two RFP processes to obtain RECs to meet the statutory benchmarks for 2011 and contribute toward meeting the benchmark for future years. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies will recover the costs of acquiring these RECs. The PUCO selected auditors to perform a financial and management audit, and final audit reports were filed with the PUCO on August 15, 2012. While generally supportive of the Ohio Companies' approach to procurement of RECs, the management/performance auditor recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state all renewable obligations that the auditor characterized as excessive. A hearing for this matter commenced on February 19, 2013, and concluded on February 25, 2013. A decision of the PUCO is expected in the third quarter of 2013.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Companies recently reported that all of the Ohio Companies met their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies intend to conduct an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to provide comments on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. The PUCO has scheduled a series of workshops for the remainder of 2013, the first of which commenced on July 9, 2013. The Ohio Companies cannot predict the outcome of this investigation.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expired on May 31, 2013, 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 descending clock auctions, competitive requests for proposals and spot market purchases. On November 17, 2011, the Pennsylvania Companies filed a Joint Petition for Approval of their DSPs that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2013 through May 31, 2015. The ALJ issued a Recommended Decision on June 15, 2012, that supported adoption of the Pennsylvania Companies' proposed wholesale procurement plans, denial of their proposed Market Adjustment Charge, and various modifications to the proposed competitive enhancements. The PPUC entered an opinion and order on August 16, 2012, which primarily resolved those issues related to procurement and rate design, but required the submission of revised proposals regarding the retail market enhancement programs. The Pennsylvania Companies filed revised proposals on the retail market enhancements on November 14, 2012. A final order was entered on February 15, 2013, which addressed minor changes to the Pennsylvania Companies' revised enhancement proposals and ordered two choices for cost recovery of those programs. On February 28, 2013, the Pennsylvania Companies filed a petition to amend the August 16, 2012, order related to the description of how the hourly industrial product is to be priced. On April 4, 2013, the PPUC entered a Final Order postponing the implementation of one of the retail market enhancements. On March 20, 2013, answers supporting and opposing the Pennsylvania Companies' February 28 petition were filed by several parties. On July 16, 2013, the PPUC entered an order granting the Pennsylvania Companies' February 28, 2013 petition, thereby amending its August 16, 2012 order and clarifying the description of the hourly industrial product pricing. The Pennsylvania Companies are actively implementing their DSPs as of June 1, 2013.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. In April 2010, ME and PN filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC's March 3, 2010 Order. On June 14, 2011, the Commonwealth Court issued an opinion and order affirming the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal on February 28, 2012, and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari on October 9, 2012. On July 13, 2011, ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania for the purpose of obtaining an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. Proceedings in the U.S. District Court effectively were suspended until conclusion of the proceedings before the United States Supreme Court. Pursuant to procedural orders issued by U.S. District Court Judge Gardner, on December 21, 2012, the PPUC submitted its motion to dismiss the U.S. District Court proceedings. ME and PN submitted their answers on January 9, 2013, and subsequent pleadings were submitted by the PPUC, ME and PN. Oral argument on the PPUC motion to dismiss took place on May 20, 2013, and the PPUC motion now is pending before the court.

In each of May 2008, 2009 and 2010, the PPUC approved ME's and PN's annual updates to their TSC rider for the annual periods between June 1, 2008 to December 31, 2010, including marginal transmission losses as approved by the PPUC, although the recovery of marginal transmission losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The PPUC's approval in May 2010 authorized an increase to the TSC for ME's customers to provide for full recovery by December 31, 2010. Although the ultimate outcome of this matter cannot be determined at this time, ME and PN believe that they should ultimately prevail through the judicial process and therefore expect to fully recover the approximately $254 million in marginal transmission losses for the period prior to January 1, 2011.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted an interim report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. The Pennsylvania Companies are expected to report their final energy efficiency and demand reduction results for the period ending May 31, 2013, by November 15, 2013.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013 the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings have been held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013 providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

In February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all RECs associated with the energy and capacity that MP is required to purchase pursuant to electric energy purchase agreements between MP and three NUG facilities in West Virginia. The City of New Martinsville and Morgantown Energy Associates, each the owner of one of the contracted resources, opposed the petition. On November 22, 2011, the WVPSC granted ownership of all RECs produced by the facilities to MP, and held that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility under PURPA owns the RECs associated with that purchase. The West Virginia Supreme Court upheld the WVPSC's decision. The City of New Martinsville and Morgantown Energy Associates filed petitions at FERC alleging the WVPSC order violated PURPA and requested that FERC initiate an enforcement action. On April 24, 2012, FERC issued an order declining to act on the petitions and instead noted that the City of New Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. MP and PE filed for rehearing of FERC's order, which was denied on September 20, 2012. The City of New Martinsville filed a complaint in the U.S. District Court for the Southern District of West Virginia on June 1, 2012, alleging that the WVPSC order violates PURPA.

Morgantown Energy Associates has joined in filing a similar complaint and requesting damages in the same U.S. District Court. MP and PE filed for judgment on the pleadings in both cases on January 25, 2013. The matters are pending in the District Court. The RECs are being used for compliance purposes and regardless of the final resolution of the ownership issue, MP and PE would expect to recover from customers costs incurred for RECs for compliance.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE have filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposes a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer would involve MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. The proposed transfer would implement a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make unhedged electricity and capacity purchases from the spot market, which is expected to result in greater rate stability for MP's customers. The plan is expected to remedy MP's capacity and energy shortfalls, which are projected to worsen due to a projected increase in annual load growth of approximately 1.4%. MP and PE will file a base rate case no later than six months from the completion of the transaction. On February 11, 2013, the WVPSC issued an order adopting a procedural schedule for this matter and testimony and briefing has followed. MP and PE also filed with FERC for authorization to effect these transfers and on April 23, 2013, FERC issued an order authorizing the transfers. MP's application for FERC authorization to effect the financing was approved on May 13, 2013. Hearings were held at the WVPSC in late May and briefs and reply briefs have been submitted. The matter is awaiting decision from the WVPSC.

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, 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 items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the 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 power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rate

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialization) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit. The PUCO and ICC also filed for review with that court. The Dayton Power & Light Company filed a Petition for Review with the U.S. Court of Appeals for the D.C. Circuit, and on May 2, 2013, FirstEnergy intervened in that proceeding. These appeals have been consolidated for briefing and disposition in the Seventh Circuit.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the New York Independent System Operator region and; (2) the PJM region and the FERC-jurisdictional members of the Southeastern Regional Transmission Planning region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that would have otherwise been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While most of the matters involved with the move have been resolved, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed; the details of the dispute are discussed below under "MISO Multi-Value Project Rule Proposal." In addition, FERC denied recovery of certain charges that collectively can be described as "exit fees" by means of ATSI's transmission rate totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. ATSI has asked for rehearing of FERC's orders that address the Michigan Thumb transmission project and the exit fee issue. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC that, if accepted by FERC, should resolve certain of the exit fee issues. Thereafter, the OCC protested the December 21, 2012 settlement filing, which remains pending before FERC. In a prior order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. On November 19, 2012, ATSI filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit of FERC's ruling on the "legacy RTEP" issue, and ATSI's initial brief was filed with that court on April 11, 2013. FERC filed its initial brief on June 25, 2013. The briefing schedule extends through August 30, 2013.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM and their impact, if any, on FirstEnergy cannot be predicted at this time.

MISO Multi-Value Project Rule Proposal

In July 2010, MISO and certain MISO transmission owners (not including ATSI or FirstEnergy) jointly filed with FERC a proposed cost allocation methodology for certain new transmission projects. The new transmission projects - described as MVPs - are a class of transmission projects that are approved via MISO's MTEP process. Under MISO's proposal, the costs of “Michigan Thumb” MVP project that was approved by MISO's Board prior to the June 1, 2011 effective date of FirstEnergy's integration into PJM would be allocated to and charged to ATSI. MISO estimated that approximately $16 million in annual revenue requirements associated with the Michigan Thumb Project would be allocated to the ATSI zone upon completion of project construction. In addition, the MISO's MVP tariffs could assess costs on PJM loads that purchase energy that has flowed over the transmission systems into the MISO.

FirstEnergy has filed pleadings in opposition to the MISO's efforts to “socialize” the costs of the Michigan Thumb Project onto ATSI or onto ATSI's customers. FirstEnergy asserts legal, factual and policy arguments. To date, FERC has responded in a series of orders that may require ATSI to absorb the charges for the Michigan Thumb Project pending the outcome of further regulatory proceedings and appeals. These further proceedings can be divided into two tracks: litigation related to MISO's generic MVP cost allocation proposal; and litigation related to MISO's "Schedule 39" tariff that purports to charge the MVP costs to ATSI.

Regarding the first litigation track, in 2010 and 2011 FERC issued orders that approved the MISO proposal. On October 31, 2011, FirstEnergy filed a Petition of Review of those orders with the U.S. Court of Appeals for the D.C. Circuit. Other parties also filed appeals of those orders and, in November 2011, the appeals were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit. Briefs were filed in late 2012 and early 2013, and the court heard oral arguments on April 10, 2013. On June 7, 2013, the Seventh Circuit issued an order that ratified FERC's acceptance of the MISO's proposed MVP tariff. The Seventh Circuit held, in relevant part, that: (i) MISO's generic MVP cost allocation proposal was just and reasonable under the FPA; and (ii) that ATSI's arguments that it should not have to pay MVP charges were being considered in the second litigation track (the "Schedule 39" proceeding") and therefore were not ripe for decision by the court. The parties that opposed the generic MVP tariff - led by the ICC and the State of Michigan - have ninety days (or until September 5, 2013) to file for appeal with the U.S. Supreme Court. FirstEnergy continues to evaluate the Seventh Circuit's order and its substantive and procedural options.

Regarding the second litigation track, in February 2012, FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. FERC set for hearing the question of whether it is just and reasonable for ATSI to pay the Michigan Thumb Project costs and, if so, the amount of and methodology for calculating ATSI's Michigan Thumb Project cost responsibility. The hearings took place in April 2013, and on July 16, 2013 the ALJ issued an Initial Decision ruling that ATSI must pay the "Schedule 39" MVP costs. Briefs on Exceptions to the Initial Decision and Briefs Opposing Exceptions are due on August 15 and September 4, 2013, respectively. Thereafter the question of whether ATSI must pay MVP charges as determined under MISO's "Schedule 39" will be presented to FERC for final decision.

FirstEnergy cannot predict the outcome of these proceedings or estimate the possible loss or range of loss.

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 U.S. Court of Appeals for 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, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. On March 13, 2013, the Ninth Circuit issued a briefing schedule with the final briefs due on October 9, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another 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 filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has 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.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012 subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project. FirstEnergy cannot predict the outcome of these matters or estimate the possible loss or range of loss.

Yards Creek

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and operates the project. PSEG Fossil, LLC owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. FERC issued a license for authorization to operate the project. The previous license expired on February 28, 2013. On May 9, 2013, FERC issued the new license for a term of 40 years. JCP&L and PSEG have notified FERC of their acceptance of the license and are implementing the license conditions.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FG. FG holds the current FERC license that authorizes ownership and operation of the project. The current FERC license will expire on November 30, 2015. FERC's regulations call for a five-year relicensing process. On November 24, 2010, and acting pursuant to applicable FERC regulations and rules, FG initiated the ILP relicensing process by filing its notice of intent to relicense and related documents in the license docket.

Section 15 of the FPA contemplates that third parties may file a "competing application" to assume ownership and operation of a hydroelectric facility upon (i) relicensure and (ii) payment of net book value of the plant to the original owner/operator. On November 30, 2010, the Seneca Nation filed its notice of intent to relicense and related documents necessary for the Seneca Nation to submit a competing application. FG believes it is entitled to a statutory “incumbent preference” under Section 15 and that it ultimately should prevail in these proceedings. Nevertheless, the Seneca Nation's pleadings reflect the Nation's apparent intent to obtain the license for the facility, and to assume ownership and operation of the facility as contemplated by the statute.

The Seneca Nation and certain other intervenors have asked FERC to redefine the “project boundary” of the hydroelectric plant to include the dam and reservoir facilities operated by the U.S. Army Corps of Engineers. On May 16, 2011, FirstEnergy filed a Petition for Declaratory Order with FERC seeking an order to exclude the dam and reservoir facilities from the project. The Seneca Nation, the New York State Department of Environmental Conservation, and the U.S. Department of Interior each submitted responses to FirstEnergy's petition, including motions to dismiss FirstEnergy's petition. The “project boundary” issue is pending before FERC.

On September 12, 2011, FirstEnergy and the Seneca Nation each filed “Revised Study Plan” documents. These documents describe the parties' respective proposals for the scope of the environmental studies that should be performed as part of the relicensing process. On January 7, 2013, FirstEnergy and the Seneca Nation submitted their respective reports for the 2012 study season. On January 31 and February 1, 2013, respectively, the Seneca Nation and FirstEnergy each submitted their respective proposed study plans for the 2013 study season. On March 4, 2013, the Seneca Nation and other parties submitted comments regarding FirstEnergy's proposed study plans. In its comments, the Seneca Nation alleges that FirstEnergy does not hold the real estate rights necessary to operate a hydroelectric project in circumstances where there is flowage over the Seneca Nation's lands. On April 3, 2013, FirstEnergy filed its response to these and other assertions by the Seneca Nation and its allied parties. On May 3, 2013, FERC's Director of the Office of Energy Projects issued FERC Staff's study plan determinations for the 2013 study year. The Director determined that water level fluctuations in the lower reservoir due to hydroelectric project operations have no discernible effect on reservoir lands or environmental resources. This finding is expected to strengthen FirstEnergy's position that the project boundary should be defined to exclude the U.S. Army Corps of Engineers dam and reservoir facilities. FERC Staff's determinations also largely adopted FirstEnergy's position and arguments as to the proper scope of environmental studies for the 2013 study season. The study processes will extend through approximately November 2013.

On July 3, 2013, FirstEnergy and the Seneca Nation each submitted "Preliminary License Proposals" in the relicensing dockets. These submissions are intended to be non-binding indications of types of project upgrades that may be proposed in the parties' respective final licensing applications, as well as an indication of the scope and direction of the parties' plans for the upcoming final licensing applications. FirstEnergy is evaluating the Seneca Nation's proposal.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, on January 3, 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. 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.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. PJM proposed an effective date for these Tariff changes of February 5, 2013. On February 5, 2013, FERC Staff issued a deficiency letter to PJM requesting additional information on certain components of the proposed MOPR reform, including the exemptions and resources qualifying for the MOPR. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also required PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 decision. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and the data that is available in the public domain about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 and Lakeshore Unit 18 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer price of the assets was approximately $21.5 million and the estimated conversion cost was approximately $60 million. The transfer of Eastlake Units 4 and 5 was completed on January 31, 2013. ATSI completed the conversion in July 2013 for Eastlake Unit 5 and is expected to complete the conversion of Eastlake Unit 4 by June 1, 2014. The transfer of each of the remaining units and conversion to synchronous condensers will occur when the use of the unit for RMR purposes is no longer required. On January 22, 2013, ATSI requested clarification or, in the alternative, rehearing with respect to a statement in the FERC order authorizing the transfer that ATSI's current formula rate does not include the accounts and components necessary to allow for recovery of the costs associated with acquisition of the transferred assets and that ATSI must make a filing under Section 205 of the FPA in order to recover those costs. ATSI believes its formula rate currently includes the necessary accounts and components to allow for such recovery and that a Section 205 filing is not required. On August 5, 2013, FERC clarified that the issue of whether the cost of the transferred facilities and any conversion costs could be included in ATSI’s formula rates is more appropriately addressed during ATSI’s yearly formula rate update process.

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. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $61.5 million in revenues that they are entitled to receive as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FirstEnergy's request for rehearing is pending before FERC.

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.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx 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.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In December 2007, the states of New Jersey and Connecticut filed CAA citizen suits in the U.S. District Court for the Eastern District of Pennsylvania alleging NSR violations at the coal-fired Portland Generation Station against GenOn Energy, Inc. (formerly RRI Energy, Inc. and the current owner and operator), Sithe Energy (the purchaser of the Portland Station from ME in 1999) and ME. Specifically, these suits allege that “modifications” at Portland Units 1 and 2 occurred between 1980 and 2005 without pre-construction NSR permitting in violation of the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. In February 2012, GenOn announced its plans to deactivate the Portland Station in January 2015 citing EPA emissions limits and compliance schedules to reduce SO_2 air emissions by approximately 81% at the Portland Station by January 6, 2015. On March 28, 2013, the Court entered summary judgment for ME, ruling that all of the New Jersey's and Connecticut's claims against ME were barred by the applicable statute of limitations and dismissing all of their claims with prejudice. On July 18, 2013, the Court entered a consent decree between the other defendants and the plaintiffs settling all other claims and requiring permanent closure of the Portland Station by June 1, 2014.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the coal-fired Portland Generation Station based on “modifications” dating back to 1986. The NOV also alleged NSR violations at the Keystone and Shawville coal-fired plants based on “modifications” dating back to 1984. ME, as a former owner of the facilities, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which held oral argument on May 15, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. 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. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional 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. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the PSD provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. The parties are awaiting a decision from the District Court, but there is no deadline for that decision. FirstEnergy is unable to predict the outcome or estimate the possible loss or range of loss.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia decided that CAIR violated the CAA but allowed CAIR to remain in effect to “temporarily preserve its environmental values” until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), 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. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-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 exemption through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an exemption through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Mansfield stations. 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. MATS has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. FirstEnergy and other entities have also petitioned EPA to reconsider and revise various regulatory requirements under MATS. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's future cost of compliance with MATS is currently estimated to be approximately $650 million.

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. On July 9, 2013, FirstEnergy announced that the Hatfield's Ferry and Mitchell stations are expected to be deactivated by October 9, 2013, subject to review for reliability impacts, if any, by PJM.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. We have asserted force majeure defenses for delivery shortfalls under certain agreements, and we are in discussion with the applicable counterparties. Under one agreement, we have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payment of approximately $45 million, and agreed to pay liquidated damages for delivery shortfalls, if any, for 2013 and 2014. As to another agreement, penalties of approximately $22 million for delivery shortfalls for 2012 could apply. If we fail to reach a resolution with applicable counterparties for the unresolved aspects of the agreements and it were ultimately determined that, contrary to our belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels), (2) prepare the United States for the impacts of climate change, and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW. The proposed new source performance standard of 1,000 lbs. CO_2/MWH, is roughly equivalent to the emission rate of a natural gas combined cycle unit and roughly 50 percent below the emission rate from coal-fired power plants operating today. On June 25, 2013, a Presidential memorandum directed EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013, and propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes 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.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. In June 2013, the period for finalizing the Section 316(b) regulation was extended to November 4, 2013. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

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 in excess of $150 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 these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River are expected to be deactivated, subject to PJM review, on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel 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 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulated with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. Depending on the content of the EPA's final effluent limitations rule and the specifics of any "alignment", the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the Resource Conservation and Recovery Act and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities 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 Sheet as of June 30, 2013 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 $124 million have been accrued through June 30, 2013. Included in the total are accrued liabilities of approximately $82 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 possible losses 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 June 30, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate. The values of FirstEnergy's NDT 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 NDT. On June 18, 2013, FE submitted a revised $125 million parental guaranty for NRC review relating to a shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. On this date, FE also submitted to the NRC a revised $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. The NRC subsequently narrowed the scope of admitted contentions in this proceeding to a challenge to the computer code used to model source terms in FENOC's SAMA analysis. On December 28, 2012, the ASLB issued two decisions that granted FENOC's motion for summary dismissal of the remaining SAMA contention and denied the Intervenors' request for a new contention on the Davis-Besse Shield Building. The ASLB declined to terminate the adjudication. In an earlier order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance until further order. In a September 6, 2012, staff requirements memorandum, the NRC directed the staff to publish a final rule and EIS to support an updated Waste Confidence Decision and temporary storage rule within 24 months. The ASLB has suspended further consideration of the Intervenors' proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

In May 2013, four petitioners requested a hearing on an NRC LAR submitted by FENOC to amend the Technical Specifications for the Davis-Besse plant to support plant operations following replacement of the steam generators, which is scheduled to be completed in April 2014. The petitioners also challenge FENOC's ability to replace the steam generators at the Davis-Besse plant under the NRC regulations, 10 CFR §50.59 without submitting a formal LAR. On June 21, 2013, both the NRC Staff and FENOC filed oppositions to the request for a hearing.

By a letter dated August 25, 2011, the NRC made a final significance determination (white) associated with a violation that occurred during the retraction of a source range monitor from the Perry reactor vessel. The NRC also placed Perry in the degraded cornerstone column (Column 3) of the NRC's Action Matrix governing the oversight of commercial nuclear reactors. As a result, the NRC staff conducted several supplemental inspections, including an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues were understood, the extent of condition was identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. On December 28, 2012, the NRC issued a report on the 95002 Inspection that concluded that FENOC "did not provide assurance that the corrective actions for performance issues associated with the Occupational Exposure Control Effectiveness PI were sufficient to address the root and contributing causes and prevent recurrence." Moreover, the NRC also concluded that FENOC "did not adequately address corrective actions for the White NOV." As a result, the NRC will hold open both a parallel PI inspection finding on the occupational exposure issues and the White finding. The NRC will conduct a future inspection to verify the effectiveness of FENOC's corrective actions. Additional adverse findings by the NRC could result in additional NRC oversight and further inspection activities.

By a letter dated January 17, 2013, the NRC notified FENOC that the Perry plant would remain in Column 3 of the action matrix for the NRC reactor oversight process. It stated that although “Perry meets the definition in Inspection Manual Chapter 0305 for Multiple/Repetitive Degraded Cornerstone, Column 4, of the Action Matrix,” current performance issues are well understood and appear to be limited to occupational radiation safety, at present and thus the regulatory actions specified for Column 3 of the Action Matrix are more appropriate. The NRC also noted that Perry would move to Column 4 if: (1) the follow-up 95002 inspection, scheduled for completion in the May-July 2013 timeframe, identifies a significant weakness in Perry's performance; (2) Perry is unable to complete corrective actions necessary to permit the follow-up 95002 inspection to be completed before the end of July 2013; or (3) if another

Greater-than-Green PI or finding is identified (other than a change of color for the current Occupational Exposure Control Effectiveness PI issue). Additional adverse findings by the NRC could result in further inspection activities and/or other regulatory actions.

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 FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE

Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal / interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only.

Other Legal Matters

On July 13, 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death, negligence, and negligent infliction of emotional distress claims. Plaintiff's decedent, Carrie Goretzka, was fatally electrocuted when she contacted a downed power line at her residence in Irwin, Pennsylvania. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty. The settlement is subject to PPUC approval.

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 other potentially material items not otherwise discussed above are described under Note 11, 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.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FirstEnergy. 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 the Allegheny facilities), and owns, through its subsidiary, NG, FirstEnergy’s nuclear generation facilities. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities. 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’ 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.

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 demand response 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.

During the second quarter FirstEnergy Corp. completed a $1.5 billion equity contribution to FES.

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: Overview, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income decreased by $168 million in the first six months of 2013 compared to the same period of 2012, as more fully described below.

Revenues -

Total revenues increased $17 million, in the first six months of 2013, compared to the same period of 2012, primarily due to growth in governmental aggregation and mass market sales and an increase in POLR and structured sales, partially offset by a decline in wholesale and direct sales. Revenues were adversely impacted by lower unit prices compared to 2012.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In millions)		
Direct	$1,406	$1,415	$(9)
Governmental Aggregation	565	466	99
Mass Market	216	159	57
POLR and Structured	535	426	109
Wholesale	128	387	(259)
Transmission	70	60	10
RECs	—	5	(5)
Other	69	54	15
Total Revenues	$2,989	$2,972	$17

MWH Sales by Channel	Six Months Ended June 30 2013	2012	Increase (Decrease)
	(In thousands)		
Direct	27,130	25,954	4.5 %
Governmental Aggregation	10,162	7,604	33.6 %
Mass Market	3,271	2,326	40.6 %
POLR and Structured	10,590	7,645	38.5 %
Wholesale	—	86	(100.0)%
Total MWH Sales	51,153	43,615	17.3 %

The decrease in Direct revenues of $9 million resulted from lower unit prices in all customer classes. Sales volumes increased due to the acquisition of new customers and weather related usage as heating degree days were 27% above 2012 levels, partially offset by cooling degree days which were 16% below 2012 levels. The increase in Governmental Aggregation of $99 million resulted from the acquisition of new customers primarily in Illinois and weather related usage partially offset by lower unit prices. The increase in Mass Market of $57 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania and weather related usage partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of June 30, 2013 as compared to 2.0 million as of June 30, 2012.

The increase in POLR and structured revenues of $109 million was due primarily to increased sales volumes in each channel, which were partially offset by lower unit prices.

Wholesale revenues decreased $259 million primarily due to lower gains of $175 million on financially settled contracts, an $82 million decrease in capacity revenues resulting primarily from lower capacity prices and $2 million in lower sales volumes. The decrease in wholesale sales volumes was due to lower generation available for sale, primarily as a result of the plants that were deactivated in 2012 and those under RMR arrangements and higher retail sales volumes.

The following tables summarize the price and volume factors contributing to changes in revenues:

Source of Change in Direct Revenues	Increase (Decrease) (In millions)
Effect of increase in sales volumes	$64
Change in prices	(73)
	$(9)

Source of Change in Governmental Aggregation Revenues	Increase (Decrease) (In millions)
Effect of increase in sales volumes	$156
Change in prices	(57)
	$99

Source of Change in Mass Market Revenues	Increase (Decrease) (In millions)

Effect of increase in sales volumes	$65
Change in prices	(8)
	$57

Source of Change in POLR and Structured Revenues	Increase (Decrease) (In millions)
Effect of increase in sales volumes	$162
Change in prices	(53)
	$109

Source of Change in Wholesale Revenues	Decrease (In millions)
Gain on settled contracts	$(175)
Effect of decrease in sales volumes	(2)
Capacity revenue	(82)
	$(259)

Operating Expenses -

Total operating expenses increased by $188 million in the first six months of 2013 compared to the same period of 2012.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first six months of 2013 compared with the same period of 2012:

Source of Change in Fuel and Purchased Power	Increase (Decrease) (In millions)
Fossil Fuel:	
Change due to increased unit costs	$17
Change due to volume consumed	(60)
	(43)
Nuclear Fuel:	
Change due to increased unit costs	5
Change due to volume consumed	(5)
	—
Non-affiliated Purchased Power:	
Change due to increased unit costs	72
Change due to volume purchased	399
Loss on settled contracts	(191)
Capacity expense	(172)
	108
Affiliated Purchased Power:	
Change due to increased unit costs	28
Change due to volume purchased	(19)
Loss on settled contracts with AE Supply	10
	19
Net Increase in Fuel and Purchased Power Costs	$84

Fuel costs decreased $43 million primarily due to lower volumes associated with the plants that were deactivated in 2012 and those under RMR arrangements partially offset by higher unit costs. The increase in unit costs is due to the settlement of past damages on a transportation contract associated with plants deactivated in 2012 and those under RMR arrangements, partially offset by lower unit prices resulting from new and restructured coal contracts. The increase in non-affiliated purchased power expense was due to higher volumes and unit prices, partially offset by fewer losses on settled contracts and lower capacity expense.

Other operating expenses increased by $80 million in the first six months of 2013, compared to the same period of 2012 due to the following:

- Fossil operating costs decreased by $26 million due primarily to lower labor costs resulting from previously deactivated units.
- Nuclear operating costs decreased by $18 million due primarily to lower contractor, materials and equipment costs. In 2013, there was a single refueling outage at Perry while there were two refueling outages during the same period of 2012.
- Transmission expenses increased $54 million due primarily to higher ancillary, network and line loss costs associated with additional retail load, partially offset by lower congestion costs.
- Other operating expenses increased by $70 million primarily due to an increase in mark-to-market expense on commodity contract positions ($83 million) partially offset by reduced lease expense from repurchasing interests in the sale and leaseback transactions during 2012.

Depreciation expense increased $22 million primarily due to credits in 2012 from a settlement with the DOE and an increase in depreciable base as a result of repurchasing interests in Bruce Mansfield and Beaver Valley Unit 2 sale leasebacks noted above.

Other Expense -

Total other expense increased by $135 million in the first six months of 2013, compared to the same period of 2012, primarily due to a $103 million loss on debt redemptions associated with the repurchase of senior notes, lower investment income of $13 million due to higher OTTI on the NDT investments and lower miscellaneous income due to proceeds on certain asset sales included in 2012.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Information” in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The management of FirstEnergy and FES, with the participation of each registrant's chief executive officer and chief financial officer, have reviewed and evaluated the effectiveness of the 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 FE and FES have concluded that their respective registrant's disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2013, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 11, Regulatory Matters, and Note 12, Commitments, Guarantees and Contingencies, of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

During the quarter ended June 30, 2013, the following risk factors were added in addition to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2012.

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.

The May 2013 PJM RPM auction for 2016/2017 capacity produced prices in the region served by our competitive generation segment that were lower than expected. This result may be a broader indication of an underlying supply/demand imbalance that will continue to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than we, or the industry at large, previously expected. As we experience these ongoing trends, we plan to fully review all facets of our operations for potential cost savings. In particular, we recently undertook a comprehensive review of competitive operations related to, among other things, plant economics, which ultimately resulted in our decision to deactivate the Hatfield's Ferry and Mitchell Power Stations. 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.

Any Denial of, or Delay in, Cost Recovery Resulting from JCP&L's Pending Base Rate Case or in Association with the Generic Storm Proceeding Before the NJBPU may Impose Risks on our Operations and may Negatively Impact our Credit Rating, Results of Operations and Financial Condition.

Our distribution rates in New Jersey are set by the NJBPU through traditional, cost-based regulated utility ratemaking. As a result, JCP&L may not be able to recover all of its increased, unexpected or necessary 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. Pursuant to the written Order of the NJBPU dated July 31, 2012, requiring JCP&L to file a base rate case to determine whether its rates are just and reasonable, it filed its base rate case petition on November 30, 2012. In a subsequent filing it updated its petition to request recovery for the impact of Hurricane Sandy. However, the NJBPU in its written Order dated May 31, 2013 held that costs associated with Hurricane Sandy and other 2012 major storms would only be reviewed in the generic storm proceedings and the recovery of such costs would not be considered in the current phase of the pending base rate case.

We can provide no assurance that JCP&L's request to increase rates in its pending base rate case, or any future proceeding, will be granted in whole or in part, or as to when it will receive a decision on such requests from the NJBPU. Any denial of, or delay in, its request to increase rates in the pending base rate case or to recover costs associated with Hurricane Sandy and other 2011 or 2012 major storms in the generic proceeding or any future proceeding could negatively impact our results of operations and financial condition. Any denial of, or delay in, the request to increase rates embodied in an Order from the NJBPU resulting from the base rate case could restrict it from fully recovering its costs of service, may impose risks on our operations, and may negatively impact our results of operations and financial condition. Also, the uncertainty regarding JCP&L's pending rate case and generic storm proceedings have already led to adverse credit rating agency action, and could lead to further adverse rating agency actions in the future.

113

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) On each of the following dates, FE issued the indicated number of shares of its common stock in connection with the exercise of certain options and the vesting of restricted stock units to four former employees of AE in transactions not involving a public offering in reliance on the exemption from registration afforded by Section 4(a)(2) of the Securities Act of 1933, as amended: September 29, 2011 - 200, November 2, 2011 - 300, December 20, 2011 - 532, March 14, 2012 - 14, March 19, 2012 - 24, April 3, 2012 - 300, December 31, 2012 - 237 and April 22, 2013 - 300.

(c) The table below includes information on a monthly basis regarding purchases of FE common stock during the second quarter of 2013:

	Period			
	April	May	June	Second Quarter
Total Number of Shares Purchased(1)	112,311	107,718	512,803	732,832
Average Price Paid per Share	$44.92	$42.00	$39.41	$40.64
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs(2)	—	—	—	—
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs	—	—	—	—

(1) Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock for some or all of the following: 2007 Incentive Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan, Director Compensation, Allegheny Energy, Inc., 1998 Long-Term Incentive Plan, Allegheny Energy, Inc., 2008 Long-Term Incentive Plan, Allegheny Energy, Inc., Non-Employee Director Stock Plan, Allegheny Energy, Inc., Amended and Restated Revised Plan for Deferral of Compensation of Directors, and Stock Investment Plan.

(2) FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

	10.1	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.
	10.2	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.
	10.3	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 FE's Form 8-K filed May 13, 2013, Exhibit 10.2, File No. 333-2100111.
(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended June 30, 2013, 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.

FES

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(A) Provided herein in electronic format as an exhibit.

* Users of this data are advised in accordance with Rule 406T of Regulation S-T promulgated by the SEC that this Interactive Data Files of FES are deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy nor FES have filed as an exhibit to this Form 10-Q 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 each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

August 6, 2013

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

/s/ K. Jon Taylor
K. Jon Taylor
Vice President, Controller
and Chief Accounting Officer

EXHIBIT INDEX

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117