FIRSTENERGY CORP
Form 10-Q
November 08, 2012

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 September 30, 2012

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
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A New Jersey Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	21-0485010

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., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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., Ohio Edison Company and Jersey Central Power & Light Company
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., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company

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 NOVEMBER 7, 2012
FirstEnergy Corp., $.10 par value	418,216,437
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
Jersey Central Power & Light Company, $10 par value	13,628,447

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company. 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 any other registrant, except that information relating to any of the FirstEnergy subsidiary registrants is also attributed to FirstEnergy Corp.

FirstEnergy Web Site

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 FirstEnergy’s Internet web site at www.firstenergycorp.com.

These reports are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post important information on 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. Information contained on FirstEnergy’s Internet web site shall not be deemed incorporated into, or to be part of, this report.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company and Jersey Central Power & Light Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are 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.
- 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.
- 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.
- Changing energy, capacity and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs.
- The continued ability of our regulated utilities to collect transition and other costs.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of CAIR, and any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules.
- 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 our plans to deactivate our older unscrubbed regulated and competitive fossil units and our plans to change the operations of certain fossil plants, including the impact on vendor commitments, and the timing of those deactivations and operational changes as they relate to, among other things, the RMR arrangements and the reliability of the transmission grid.
- Issues that could result from the NRC's review of the indications of cracking in the Davis Besse Plant shield building.
- 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 transmission service charge riders.
- The continuing availability of generating units, changes in their operational status and any related impacts on 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 mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates.
- The ability to accomplish or realize anticipated benefits from strategic goals.
- 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 and Competitive Energy Services segments.
- 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.
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- The ability to access the public securities and other capital and credit markets in accordance with our financing plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Changes in general economic conditions affecting us and our subsidiaries.
- Interest rates and any actions taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increased costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- The state of the national and regional economy and its impact on our major industrial and commercial customers.
- Issues concerning the soundness 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 annual period may in the aggregate vary from the indicated amount 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.

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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
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
FGCO	FirstEnergy Generation Corp., 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 that owns Global Rail and Signal Peak
Global Rail	A subsidiary of Global Holdings 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
NGC	FirstEnergy Nuclear Generation Corp., 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
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
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 Holdings 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:

ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
AEP	American Electric Power Company, Inc.
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service

GLOSSARY OF TERMS, Continued

BTU	British Thermal Units
CAA	Clean Air Act
CAL	Confirmatory Action Letter
CAIR	Clean Air Interstate Rule
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DCR	Delivery Capital Recovery Rider
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EHB	Environmental Hearing Board
EIS	Environmental Impact Statement
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
ICG	International Coal Group Inc.
ILP	Integrated License Application Process
IRS	Internal Revenue Service
IT	Information Technology
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LOC	Letter of Credit
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midwest Independent Transmission System Operator, Inc.

Moody's	Moody's Investors Service, Inc.
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-value Project
MW	Megawatt

GLOSSARY OF TERMS, Continued

MWH	Megawatt-hour
NCEA	NERC Compliance Enforcement Authority
NDT	Nuclear Decommissioning Trust
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
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
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection LLC
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
REC	Renewable Energy Credit
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMI	Retail Markets Investigation
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SAMA	Severe Accident Mitigation Alternatives
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
SREC	Solar Renewable Energy Credit
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load

GLOSSARY OF TERMS, Continued

TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(In millions, except per share amounts)	Three Months Ended September 30 2012	2011	Nine Months Ended September 30 2012	2011
REVENUES:				
Electric utilities	$2,624	$3,041	$7,414	$7,966
Unregulated businesses	1,687	1,678	4,844	4,389
Total revenues*	4,311	4,719	12,258	12,355
OPERATING EXPENSES:				
Fuel	636	632	1,833	1,720
Purchased power	1,312	1,349	3,815	3,755
Other operating expenses	856	993	2,582	3,051
Provision for depreciation	282	297	859	809
Amortization of regulatory assets, net	61	122	198	344
General taxes	257	269	761	748
Total operating expenses	3,404	3,662	10,048	10,427
OPERATING INCOME	907	1,057	2,210	1,928
OTHER INCOME (EXPENSE):				
Investment income	39	48	63	100
Interest expense	(230)	(267)	(750)	(763)
Capitalized interest	18	17	54	55
Total other expense	(173)	(202)	(633)	(608)
INCOME BEFORE INCOME TAXES	734	855	1,577	1,320
INCOME TAXES	309	325	658	550
NET INCOME	425	530	919	770
Income (loss) attributable to noncontrolling interest	—	(2)	1	(17)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$425	$532	$918	$787
EARNINGS PER SHARE OF COMMON STOCK:				
Basic	$1.02	$1.27	$2.20	$2.01
Diluted	$1.01	$1.27	$2.19	$2.00
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	417	418	418	392
Diluted	419	420	419	394
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$1.10	$1.10	$1.65	$1.65

* Includes excise tax collections of $123 million and $137 million in the three months ended September 30, 2012 and 2011, respectively, and $351 million and $371 million in the nine months ended September 30, 2012 and 2011, respectively.

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2012	2011	2012	2011
NET INCOME	$425	$530	$919	$770
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(47)	(48)	(148)	(44)
Amortized losses on derivative hedges	—	2	1	13
Change in unrealized gain on available-for-sale securities	1	(26)	13	(7)
Other comprehensive loss	(46)	(72)	(134)	(38)
Income tax benefits on other comprehensive loss	(24)	(26)	(75)	(12)
Other comprehensive loss, net of tax	(22)	(46)	(59)	(26)
COMPREHENSIVE INCOME	403	484	860	744
Comprehensive income (loss) attributable to noncontrolling interest	—	(2)	1	(17)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$403	$486	$859	$761

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)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$150	$202
Receivables-		
Customers, net of allowance for uncollectible accounts of $43 in 2012 and $37 in 2011	1,604	1,525
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	227	269
Materials and supplies	875	811
Prepaid taxes	227	191
Derivatives	212	235
Accumulated deferred income taxes	224	—
Other	190	122
	3,709	3,355
PROPERTY, PLANT AND EQUIPMENT:		
In service	41,756	40,122
Less — Accumulated provision for depreciation	12,434	11,839
	29,322	28,283
Construction work in progress	2,119	2,054
	31,441	30,337
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,203	2,112
Investments in lease obligation bonds	210	402
Other	1,038	1,008
	3,451	3,522
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,444	6,441
Regulatory assets	2,113	2,030
Other	1,580	1,641
	10,137	10,112
	$48,738	$47,326
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,473	$1,621
Short-term borrowings	1,604	—
Accounts payable	925	1,174
Accrued taxes	508	558
Accrued compensation and benefits	313	384
Derivatives	155	218
Other	942	900
	5,920	4,855
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	9,758	9,765
Accumulated other comprehensive income	367	426
Retained earnings	3,266	3,047
Total common stockholders’ equity	13,433	13,280
Noncontrolling interest	16	19
Total equity	13,449	13,299
Long-term debt and other long-term obligations	15,627	15,716
	29,076	29,015
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,543	5,670
Retirement benefits	2,271	2,823
Asset retirement obligations	1,574	1,497
Deferred gain on sale and leaseback transaction	900	925
Adverse power contract liability	550	469
Other	1,904	2,072
	13,742	13,456
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$48,738	$47,326

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In millions)	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$919	$770
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	859	809
Amortization of regulatory assets, net	198	344
Nuclear fuel and lease amortization	163	152
Deferred purchased power and other costs	(214)	(222)
Deferred income taxes and investment tax credits, net	712	696
Deferred rents and lease market valuation liability	(62)	(17)
Accrued compensation and retirement benefits	(168)	(25)
Commodity derivative transactions, net	(80)	(22)
Pension trust contributions	(600)	(375)
Asset impairments	10	59
Cash collateral, net	(3)	(66)
Decrease (increase) in operating assets-		
Receivables	(41)	139
Materials and supplies	(63)	62
Prepayments and other current assets	(151)	(1)
Increase (decrease) in operating liabilities-		
Accounts payable	(250)	(154)
Accrued taxes	(50)	20
Accrued interest	50	67
Other	47	(7)
Net cash provided from operating activities	1,276	2,229
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	660	603
Short-term borrowings, net	1,604	—
Redemptions and Repayments-		
Long-term debt	(870)	(1,581)
Short-term borrowings, net	—	(700)
Common stock dividend payments	(690)	(651)
Other	(42)	(73)
Net cash provided from (used for) financing activities	662	(2,402)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,686)	(1,464)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	2,133	3,678
Purchases of investment securities held in trusts	(2,188)	(3,801)
Cash investments	100	51

Cash received in AE merger	—	590
Cost of removal	(119)	(57)
Other	(40)	(6)
Net cash used for investing activities	(1,990)	(555)
Net change in cash and cash equivalents	(52)	(728)
Cash and cash equivalents at beginning of period	202	1,019
Cash and cash equivalents at end of period	$150	$291
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction: merger with AE, common stock issued	$—	$4,354

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2012	2011	2012	2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales to non-affiliates	$1,339	$1,251	$3,964	$3,348
Electric sales to affiliates	155	143	385	574
Other	63	73	180	229
Total revenues	1,557	1,467	4,529	4,151
OPERATING EXPENSES:				
Fuel	303	386	978	1,045
Purchased power from affiliates	131	55	381	189
Purchased power from non-affiliates	499	328	1,420	954
Other operating expenses	343	390	1,031	1,268
Provision for depreciation	71	69	203	207
General taxes	35	31	104	91
Impairment of long-lived assets	—	2	—	22
Total operating expenses	1,382	1,261	4,117	3,776
OPERATING INCOME	175	206	412	375
OTHER INCOME (EXPENSE):				
Investment income	38	28	50	50
Miscellaneous income	1	9	25	17
Interest expense — affiliates	(3)	(2)	(7)	(5)
Interest expense — other	(51)	(51)	(140)	(156)
Capitalized interest	9	8	27	28
Total other expense	(6)	(8)	(45)	(66)
INCOME BEFORE INCOME TAXES	169	198	367	309
INCOME TAXES	68	78	145	115
NET INCOME	$101	$120	$222	$194
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$101	$120	$222	$194
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(5)	(5)	(2)	(14)
Amortized gain (loss) on derivative hedges	(2)	(1)	(6)	4
Change in unrealized gain on available-for-sale securities	(2)	(22)	11	(7)
Other comprehensive income (loss)	(9)	(28)	3	(17)
Income taxes (benefits) on other comprehensive income (loss)	(3)	(11)	1	(7)

Other comprehensive income (loss), net of tax	(6)	(17)	2	(10)
COMPREHENSIVE INCOME	$95	$103	$224	$184

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

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FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$3	$7
Receivables-		
Customers, net of allowance for uncollectible accounts of $16 in 2012 and 2011	485	424
Affiliated companies	402	600
Other, net of allowance for uncollectible accounts of $2 in 2012 and $3 in 2011	103	61
Notes receivable from affiliated companies	438	383
Materials and supplies	533	492
Derivatives	209	219
Prepayments and other	137	38
	2,310	2,224
PROPERTY, PLANT AND EQUIPMENT:		
In service	11,638	10,983
Less — Accumulated provision for depreciation	4,312	4,110
	7,326	6,873
Construction work in progress	1,055	1,014
	8,381	7,887
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,286	1,223
Other	16	7
	1,302	1,230
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	114	123
Goodwill	24	24
Property taxes	43	43
Unamortized sale and leaseback costs	111	80
Derivatives	78	79
Other	181	129
	551	478
	$12,544	$11,819
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,074	$905
Accounts payable-		
Affiliated companies	787	436
Other	174	220
Accrued taxes	83	227
Derivatives	153	189
Other	244	261
	2,515	2,238
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding	1,571	1,570

Accumulated other comprehensive income	78	76
Retained earnings	2,153	1,931
Total common stockholder's equity	3,802	3,577
Long-term debt and other long-term obligations	3,085	2,799
	6,887	6,376
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	900	925
Accumulated deferred income taxes	501	286
Asset retirement obligations	950	904
Retirement benefits	183	356
Lease market valuation liability	87	171
Other	521	563
	3,142	3,205
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$12,544	$11,819

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

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

(In millions)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$222	$194
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	203	207
Nuclear fuel and lease amortization	159	151
Deferred rents and lease market valuation liability	(144)	(37)
Deferred income taxes and investment tax credits, net	123	246
Asset impairments	8	40
Accrued compensation and retirement benefits	11	(31)
Pension trust contribution	(209)	—
Commodity derivative transactions, net	(67)	(54)
Cash collateral, net	(4)	(81)
Decrease (increase) in operating assets-		
Receivables	95	(34)
Materials and supplies	(40)	72
Prepayments and other current assets	5	8
Increase (decrease) in operating liabilities-		
Accounts payable	292	(113)
Accrued taxes	(144)	24
Other	(9)	(55)
Net cash provided from operating activities	501	537
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	560	247
Short-term borrowings, net	3	—
Redemptions and repayments-		
Long-term debt	(246)	(791)
Short-term borrowings, net	—	(12)
Other	(9)	(10)
Net cash provided from (used for) financing activities	308	(566)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(535)	(408)
Nuclear fuel	(207)	(65)
Proceeds from asset sales	17	519
Sales of investment securities held in trusts	1,167	1,613
Purchases of investment securities held in trusts	(1,194)	(1,654)
Loans to affiliated companies, net	(55)	57
Other	(6)	(36)
Net cash provided from (used for) investing activities	(813)	26

Net change in cash and cash equivalents	(4)	(3)
Cash and cash equivalents at beginning of period	7	9
Cash and cash equivalents at end of period	$3	$6

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

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OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$426	$441	$1,149	$1,165
Excise and gross receipts tax collections	28	29	79	82
Total revenues	454	470	1,228	1,247
OPERATING EXPENSES:				
Purchased power from affiliates	38	57	128	220
Purchased power from non-affiliates	79	80	215	203
Other operating expenses	124	114	364	316
Provision for depreciation	26	23	75	69
Amortization of regulatory assets, net	42	46	57	49
General taxes	52	51	148	146
Total operating expenses	361	371	987	1,003
OPERATING INCOME	93	99	241	244
OTHER INCOME (EXPENSE):				
Investment income	8	11	17	20
Interest expense	(23)	(22)	(68)	(66)
Capitalized interest	—	—	2	1
Total other expense	(15)	(11)	(49)	(45)
INCOME BEFORE INCOME TAXES	78	88	192	199
INCOME TAXES	34	34	76	72
NET INCOME	$44	$54	$116	$127
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$44	$54	$116	$127
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(7)	(6)	(24)	(21)
Change in unrealized gain on available-for-sale securities	—	(3)	—	(1)
Other comprehensive loss	(7)	(9)	(24)	(22)
Income tax benefits on other comprehensive loss	(4)	(4)	(13)	(11)
Other comprehensive loss, net of tax	(3)	(5)	(11)	(11)
COMPREHENSIVE INCOME	$41	$49	$105	$116

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

OHIO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$50	$26
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and 2011	179	163
Affiliated companies	52	86
Other	20	41
Notes receivable from affiliated companies	258	181
Prepayments and other	9	17
	568	514
UTILITY PLANT:		
In service	3,490	3,358
Less — Accumulated provision for depreciation	1,308	1,267
	2,182	2,091
Construction work in progress	96	91
	2,278	2,182
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	148	163
Nuclear plant decommissioning trusts	141	137
Other	91	90
	380	390
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	293	363
Property taxes	81	81
Unamortized sale and leaseback costs	21	25
Other	27	19
	422	488
	$3,648	$3,574
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$3	$2
Accounts payable-		
Affiliated companies	81	119
Other	30	35
Accrued taxes	94	88
Accrued interest	25	25
Other	111	79
	344	348
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 175,000,000 shares – 60 shares outstanding	698	747
Accumulated other comprehensive income	43	54
Retained earnings (accumulated deficit)	32	(84)

Total common stockholder's equity	773	717
Noncontrolling interest	5	5
Total equity	778	722
Long-term debt and other long-term obligations	1,157	1,155
	1,935	1,877
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	812	787
Retirement benefits	208	213
Asset retirement obligations	75	71
Other	274	278
	1,369	1,349
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$3,648	$3,574

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

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$116	$127
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	75	69
Amortization of regulatory assets, net	57	49
Amortization of lease costs	28	28
Deferred income taxes and investment tax credits, net	41	72
Accrued compensation and retirement benefits	(35)	(25)
Pension trust contribution	—	(27)
Decrease (increase) in operating assets-		
Receivables	42	50
Prepayments and other current assets	8	(30)
Increase (decrease) in operating liabilities-		
Accounts payable	(43)	(23)
Accrued taxes	7	—
Other	7	(6)
Net cash provided from operating activities	303	284
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(1)	(1)
Short-term borrowings, net	—	(142)
Common stock dividend payments	(50)	(268)
Other	(1)	(2)
Net cash used for financing activities	(52)	(413)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(147)	(123)
Sales of investment securities held in trusts	57	154
Purchases of investment securities held in trusts	(63)	(161)
Loans to affiliated companies, net	(77)	(163)
Cash investments	13	12
Other	(10)	(10)
Net cash used for investing activities	(227)	(291)
Net change in cash and cash equivalents	24	(420)
Cash and cash equivalents at beginning of period	26	420
Cash and cash equivalents at end of period	$50	$—

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2012	2011	2012	2011
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$625	$762	$1,579	$1,973
Excise tax collections	11	15	29	39
Total revenues	636	777	1,608	2,012
OPERATING EXPENSES:				
Purchased power	331	429	849	1,127
Other operating expenses	84	126	246	279
Provision for depreciation	33	33	95	87
Amortization (deferral) of regulatory assets, net	2	(4)	30	118
General taxes	17	20	44	53
Total operating expenses	467	604	1,264	1,664
OPERATING INCOME	169	173	344	348
OTHER INCOME (EXPENSE):				
Miscellaneous income	1	4	3	9
Interest expense	(31)	(32)	(92)	(93)
Capitalized interest	—	1	1	2
Total other expense	(30)	(27)	(88)	(82)
INCOME BEFORE INCOME TAXES	139	146	256	266
INCOME TAXES	62	61	114	113
NET INCOME	$77	$85	$142	$153
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$77	$85	$142	$153
OTHER COMPREHENSIVE LOSS:				
Pensions and OPEB prior service costs	(6)	(6)	(18)	(17)
Other comprehensive loss	(6)	(6)	(18)	(17)
Income tax benefits on other comprehensive loss	(4)	(2)	(11)	(7)
Other comprehensive loss, net of tax	(2)	(4)	(7)	(10)
COMPREHENSIVE INCOME	$75	$81	$135	$143

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Receivables-		
Customers, net of allowance for uncollectible accounts of $4 in 2012 and $3 in 2011	$250	$235
Affiliated companies	40	—
Other	18	17
Prepaid taxes	71	33
Other	43	19
	422	304
UTILITY PLANT:		
In service	5,124	4,872
Less — Accumulated provision for depreciation	1,797	1,743
	3,327	3,129
Construction work in progress	114	227
	3,441	3,356
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	229	219
Nuclear plant decommissioning trusts	199	193
Other	2	2
	430	414
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,811	1,811
Regulatory assets	526	408
Other	29	32
	2,366	2,251
	$6,659	$6,325
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$35	$34
Short-term borrowings-		
Affiliated companies	350	259
Accounts payable-		
Affiliated companies	1	19
Other	95	101
Accrued compensation and benefits	35	41
Customer deposits	24	24
Accrued interest	30	18
Other	29	36
	599	532
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, $10 par value, authorized 16,000,000 shares, 13,628,447 shares outstanding	136	136
Other paid-in capital	2,011	2,011

Accumulated other comprehensive income	32	39
Retained earnings	173	121
Total common stockholder's equity	2,352	2,307
Long-term debt and other long-term obligations	1,711	1,736
	4,063	4,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	1,023	859
Power purchase contract liability	267	147
Nuclear fuel disposal costs	197	197
Retirement benefits	163	170
Asset retirement obligations	121	115
Other	226	262
	1,997	1,750
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$6,659	$6,325

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In millions)	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$142	$153
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	95	87
Amortization of regulatory assets, net	30	118
Deferred purchased power and other costs	(95)	(84)
Deferred income taxes and investment tax credits, net	156	83
Accrued compensation and retirement benefits	(31)	(12)
Pension trust contribution	—	(105)
Decrease (increase) in operating assets-		
Receivables	(57)	85
Prepaid taxes	(38)	(59)
Decrease in operating liabilities-		
Accounts payable	(24)	(60)
Accrued taxes	(6)	(1)
Accrued interest	12	12
Other	24	10
Net cash provided from operating activities	208	227
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	91	312
Redemptions and Repayments-		
Long-term debt	(24)	(23)
Common stock dividend payments	(90)	(500)
Other	—	(2)
Net cash used for financing activities	(23)	(213)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(157)	(160)
Loans to affiliated companies, net	—	177
Sales of investment securities held in trusts	376	610
Purchases of investment securities held in trusts	(387)	(624)
Other	(17)	(17)
Net cash used for investing activities	(185)	(14)
Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	—	—
Cash and cash equivalents at end of period	$—	$—

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 (FGCO and NGC), and FESC. AE merged with a subsidiary of FirstEnergy on February 25, 2011, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FirstEnergy. Accordingly, consolidated results of operations for the nine months ended September 30, 2011, include just seven months of Allegheny results.

The consolidated financial statements of FE, FES, OE and JCP&L include the accounts of entities in which a controlling financial interest is held, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or the result of an analysis that identifies FE or one of its subsidiaries as the primary beneficiary of a VIE. Investments in which a controlling financial interest is not held are accounted for under the equity or cost method of accounting.

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, 2011.

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.

As described in its Annual Report on Form 10-K for the year ended December 31, 2011, FE's consolidated financial statements for the nine months ended September 30, 2011, were revised to reflect a purchase accounting measurement adjustment identified during the fourth quarter of 2011 that decreased goodwill and increased income tax expense by approximately $20 million.

As described in its Annual Report on Form 10-K for the year ended December 31, 2011, during the fourth quarter of 2011, FE elected to change its method of accounting relating to its defined benefit pension and OPEB plans to recognize the change in fair value of plan assets and net actuarial gains and losses immediately, and applied this change retrospectively. Generally, these gains and losses are measured annually as of December 31, and accordingly, will be recorded during the fourth quarter.

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. GOODWILL

On January 1, 2012, FirstEnergy adopted the amendment to the authoritative accounting guidance regarding the testing for goodwill impairment that provides the option to apply a qualitative assessment to determine whether or not it is necessary to apply the traditional two-step quantitative goodwill impairment test.

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, a likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying amount. If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing of goodwill assigned to its reporting units is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify potential goodwill impairment and measure the amount of goodwill impaired to be recognized, if any.

The 2012 annual goodwill impairment test was performed during the third quarter primarily using a qualitative assessment approach. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its reporting units. FirstEnergy's reporting units are consistent with its operating entities, which aggregate to reportable segments and consist of Regulated Distribution, Regulated Transmission and Competitive Energy Services. Goodwill is allocated to these reportable segments based on the original purchase price allocation for acquisitions within the various reporting units.

As of September 30, 2012, goodwill balances for the Regulated Distribution, Regulated Transmission and Competitive Energy Services segments were $5,025 million, $526 million and $893 million, respectively. It was determined that the fair values of FirstEnergy's reporting units were, more likely than not, greater than their carrying values. No further goodwill testing was completed and no impairment was recognized.

3. EARNINGS PER SHARE

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 September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
	(In millions, except per share amounts)			
Weighted average number of basic shares outstanding	417	418	418	392
Assumed exercise of dilutive stock options and awards[(1)]	2	2	1	2
Weighted average number of diluted shares outstanding	419	420	419	394
Earnings Available to FirstEnergy Corp.	$425	$532	$918	$787
Basic earnings per share of common stock	$1.02	$1.27	$2.20	$2.01
Diluted earnings per share of common stock	$1.01	$1.27	$2.19	$2.00

(1) 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 and nine months ended September 30, 2012 and 2011.

4. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy’s pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the nine months ended September 30, 2012, FirstEnergy made a voluntary $600 million contribution to its qualified pension plan. No additional contributions are expected to be made in 2012.

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

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended September 30,	2012	2011	2012	2011

	(In millions)			
Service cost	$40	$34	$3	$3
Interest cost	97	96	12	12
Expected return on plan assets	(121)	(115)	(9)	(10)
Amortization of prior service cost	3	4	(51)	(51)
Net periodic costs (credits)	$19	$19	$(45)	$(46)

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Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
Service cost	$120	$97	$9	$9
Interest cost	291	276	36	35
Expected return on plan assets	(363)	(332)	(27)	(30)
Amortization of prior service cost	9	12	(153)	(150)
Other adjustments (settlements, curtailments, etc)	—	7	—	—
Net periodic costs (credits)	$57	$60	$(135)	$(136)

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

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$14	$14	$(30)	$(31)
FES	12	7	(8)	(8)
OE	(1)	(2)	(5)	(5)
JCP&L	(2)	(3)	(3)	(2)

Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2012	2011	2012	2011
	(In millions)			
FirstEnergy	$41	$48	$(92)	$(97)
FES	33	21	(24)	(24)
OE	(3)	(6)	(16)	(16)
JCP&L	(5)	(8)	(7)	(7)

5. 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. During the second quarter of 2012, FirstEnergy reached a settlement with state authorities related to state apportionment factors in Pennsylvania on an intercompany asset sale, which favorably affected FirstEnergy's effective tax rate by $3 million in the nine months ended September 30, 2012. Earlier in the year, the federal government issued further guidance related to the tax accounting of costs to repair and maintain fixed assets. This guidance provided a safe harbor method of tax accounting for the Allegheny companies and allowed these companies to reduce their amount of unrecognized tax benefits by $21 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, with no resulting impact to FirstEnergy's effective tax rate for the first nine months of 2012. In the second quarter of 2011, FirstEnergy reached a settlement with the IRS on a research and development claim and recognized approximately $30 million of income tax benefits, including $5 million that favorably affected FirstEnergy's effective tax rate in the first nine months of 2011. There were no other material changes to FirstEnergy's unrecognized income tax benefits during the first nine months of 2012 or 2011.

As of September 30, 2012, it is reasonably possible that approximately $40 million of unrecognized income tax benefits may be resolved within the next twelve months, of which approximately $6 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized income tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

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 nine months of 2012, there were no material changes to the amount of accrued interest. The interest associated with the settlement of the claim in 2011 noted above favorably affected FirstEnergy's effective tax rate by $6 million in the first nine months of 2011. During the first nine months of 2011, there were no other material changes to the amount of accrued interest, except for a $6 million increase in accrued interest from the merger with AE in the first quarter of 2011. The net amount of interest accrued as of September 30, 2012 was $12 million, compared with $11 million as of December 31, 2011.

As a result of the non-deductible portion of merger transaction costs, FirstEnergy's effective tax rate was unfavorably impacted by $28 million in the first nine months of 2011.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2011) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2011, and additionally 2001 and 2008 for Pennsylvania. The IRS completed its audits of tax year 2008 in July 2010 and tax year 2009 in April 2011, with both tax years having one open item. Tax years 2010-2011 are under review by the IRS. Allegheny is currently under audit by the IRS for tax years 2009-2011. State tax returns for tax years 2009 through 2011 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition, results of operations, cash flow or liquidity.

6. 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. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy’s consolidated financial statements for the third quarter of 2012 are: the PNBV and Shippingport capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L’s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station and JCP&L's supply of BGS, of which $253 million was outstanding as of September 30, 2012; and special purpose limited liability companies of MP and PE created to issue environmental control bonds that were used to construct environmental control facilities, of which $493 million was outstanding as of September 30, 2012. 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 nine months ended September 30, 2012, was primarily due to net income attributable to noncontrolling interests of $1 million, offset by $4 million in distributions to owners.

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

Mining Operations

On October 18, 2011, Pinesdale LLC, a subsidiary of Gunvor Group, Ltd., purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. FEV retained a 33-1/3% equity ownership in Global Holding, the holding company for the joint venture. Prior to the sale, FirstEnergy consolidated this joint venture since FEV was determined to be the primary beneficiary of the VIE. As a result of the sale, FEV was no longer determined to be the primary beneficiary and its retained 33-1/3% interest is subsequently accounted for using the equity method of accounting.

PATH-WV

PATH was formed to construct, through its operating companies, the PATH project, which is a high-voltage transmission line that was proposed to extend from West Virginia through Virginia and into Maryland, including 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 as directed by PJM. 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 officially removed the PATH project from its long-range expansion plans. Citing a slow economy for reducing the projected growth in electricity use, PJM said its updated analysis no longer indicates a need for the $2.1 billion, 275-mile transmission line to maintain grid stability. A joint venture between Allegheny and AEP, the project was suspended by PJM in February 2011. PATH expects to recover approximately $121 million of costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) over the next 5 years, of which $62 million relates to PATH-Allegheny and approximately $59 million relates to PATH-WV. See Note 9, Regulatory Matters, of the Combined Notes to the Consolidated Financial Statements 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 if the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, ME, PN, PE, WP and MP, maintains 21 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA as of September 30, 2012. In October 2012, one of JCP&L's long-term power purchase agreements with a NUG entity ended. 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 three of these NUG entities, its subsidiaries do not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. JCP&L, PE and WP may hold variable interests in the remaining three entities; however, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities. One of JCP&L's NUG contracts, to which the scope exception was applied, expired during 2011.

Because JCP&L, PE and WP have no equity or debt interests in the NUG entities, their maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred by its subsidiaries to be recovered from customers, except as described further below. Purchased power costs related to the three contracts that may contain a variable interest that were held by FE subsidiaries during the three months ended September 30, 2012, were $19 million, $30 million and $16 million for JCP&L, PE and WP, respectively, and $46 million, $89 million and $49 million for the nine months ended September 30, 2012, respectively. Purchased power costs related to the four contracts that may contain a variable interest that were held by JCP&L, PE and WP, during the three months ended September 30, 2011, were $44 million, $31 million, and $14 million, respectively, and $164 million, $89 million and $40 million for the nine months ended September 30, 2011, respectively.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity wherein WP may hold a variable interest, for which WP has taken the scope exception. As of September 30, 2012, WP's reserve for this adverse purchase power commitment was $45 million, including a current liability of $11 million, and is being amortized over the life of the commitment.

Loss Contingencies

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.

On August 24, 2012, NGC repurchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $108 million. Additionally, during the third quarter of 2012, FGCO acquired certain lessor equity interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for an aggregate purchase price of approximately $95.4 million; during the fourth quarter of 2012, additional equity purchases of $37.6 million, as well as an early buyout for $23.6 million occurred.

FES, OE 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 September 30, 2012:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,339	$1,123	$216
OE	551	390	161
Other FE subsidiaries	561	326	235

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.4 billion.

7. FAIR VALUE MEASUREMENTS
RECURRING AND NONRECURRING FAIR VALUE MEASUREMENTS

On January 1, 2012, FirstEnergy adopted an amendment to the authoritative accounting guidance regarding fair value measurements. The amendment was applied prospectively and expanded disclosure requirements for fair value measurements, particularly for Level 3 measurements, among other changes.

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques for Level 2 and Level 3 are as follows:

Level 1 - Quoted prices for identical instruments in active 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 the Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs and NUGs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are subsequently adjusted to fair value using a mark-to-model methodology on a monthly basis, which approximates market. The primary inputs into the model, which are generally less observable from 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 8, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value using a mark-to-model methodology on a quarterly basis, which approximates market. The primary unobservable inputs into the model are regional power prices and generation 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 IntercontinentalExchange 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 using a mark-to-model methodology on a quarterly basis, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Quarterly pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices for the 2015/2016 delivery year and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2015/2016 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 September 30, 2012, from those used as of December 31, 2011. 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 nine months ended September 30, 2012. 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	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,012	$—	1,012	$—	$1,544	$—	$1,544
Derivative assets - commodity contracts	3	257	—	260	—	264	—	264
Derivative assets - FTRs	—	—	7	7	—	—	1	1
Derivative assets - NUG contracts(1)	—	—	18	18	—	—	56	56
Equity securities(2)	367	—	—	367	259	—	—	259
Foreign government debt securities	—	60	—	60	—	3	—	3
U.S. government debt securities	—	184	—	184	—	148	—	148
U.S. state debt securities	—	314	—	314	—	314	—	314
Other(3)	124	562	—	686	49	225	—	274
Total assets	494	2,389	25	2,908	308	2,498	57	2,863
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(247)	—	(247)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(23)	(23)
Derivative liabilities - NUG contracts(1)	—	—	(300)	(300)	—	—	(349)	(349)
Derivative liabilities - LCAPP contracts(1)	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	(177)	(453)	(630)	—	(247)	(372)	(619)
Net assets (liabilities)(4)	$494	$2,212	$(428)	$2,278	$308	$2,251	$(315)	$2,244

(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.
(3) Primarily consists of short-term cash investments.
(4) Excludes $43 million and $(52) million as of September 30, 2012 and December 31, 2011, 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 September 30, 2012 and December 31, 2011:

	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, 2011 Balance	$122	$(466)	$(344)	$—	$—	$—	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(58)	(144)	(202)	—	—	—	2	(27)	(25)
Purchases	—	—	—	—	—	—	13	(4)	9
Issuances	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	(7)	261	254	—	—	—	(14)	20	6
Transfers in (out) of Level 3	—	—	—	—	—	—	—	(12)	(12)
December 31, 2011 Balance	$57	$(349)	$(292)	$—	$—	$—	$1	$(23)	$(22)
Realized gain (loss)	—	—	—	—	—	—	—	—	—
Unrealized gain (loss)	(39)	(144)	(183)	—	3	3	1	(4)	(3)
Purchases	—	—	—	—	(145)	(145)	12	(10)	2
Issues	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—
Settlements	—	193	193	—	—	—	(7)	26	19
Transfers in (out) of Level 3	—	—	—	—	—	—	—	—	—
September 30, 2012 Balance	$18	$(300)	$(282)	$—	$(142)	$(142)	$7	$(11)	$(4)

(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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(4)	Model	RTO auction clearing prices	($3.80) to $6.40	$0.50	Dollars/MWH
NUG Contracts	$(282)	Model	Generation Electricity regional prices	700 to 6,748,000 $43.40 to $57.30	3,211,000 $51.90	MWH Dollars/MWH
LCAPP Contracts	$(142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

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FES

Recurring Fair Value Measurements	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$437	$—	$437	$—	$1,010	$—	$1,010
Derivative assets - commodity contracts	3	252	—	255	—	248	—	248
Derivative assets - FTRs	—	—	5	5	—	—	1	1
Equity securities[1]	334	—	—	334	124	—	—	124
Foreign government debt securities	—	50	—	50	—	3	—	3
U.S. government debt securities	—	21	—	21	—	7	—	7
U.S. state debt securities	—	—	—	—	—	5	—	5
Other[2]	—	396	—	396	—	132	—	132
Total assets	337	1,156	5	1,498	124	1,405	1	1,530
Liabilities								
Derivative liabilities - commodity contracts	—	(177)	—	(177)	—	(234)	—	(234)
Derivative liabilities - FTRs	—	—	(7)	(7)	—	—	(7)	(7)
Total liabilities	—	(177)	(7)	(184)	—	(234)	(7)	(241)
Net assets (liabilities)[3]	$337	$979	$(2)	$1,314	$124	$1,171	$(6)	$1,289

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $47 million and $(58) million as of September 30, 2012 and December 31, 2011, 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 September 30, 2012 and December 31, 2011:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
January 1, 2011 Balance	$—	$—	$—
Realized gain (loss)	—	—	—
Unrealized gain (loss)	4	(8)	(4)
Purchases	2	(1)	1
Issuances	—	—	—
Sales	—	—	—
Settlements	(5)	2	(3)
Transfers in (out) of Level 3	—	—	—
December 31, 2011 Balance	$1	$(7)	$(6)
Realized gain (loss)	—	—	—
Unrealized gain (loss)	1	(2)	(1)
Purchases	8	(7)	1
Issues	—	—	—

Sales	—	—	—
Settlements	(5)	9	4
Transfers in (out) of Level 3	—	—	—
September 30, 2012 Balance	$5	$(7)	$(2)

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 September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(2)	Model	RTO auction clearing prices	($3.80) to $6.40	$0.30	Dollars/MWH

OE

Recurring Fair Value Measurements	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$—	$—	$—	$—	$3	$—	$3
U.S. government debt securities	—	138	—	138	—	132	—	132
Other[1]	—	3	—	3	—	2	—	2
Total assets[2]	$—	$141	$—	$141	$—	$137	$—	$137

(1) Primarily consists of short-term cash investments.

(2) Excludes $1 million and $1 million as of September 30, 2012 and December 31, 2011, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

JCP&L

Recurring Fair Value Measurements	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$139	$—	$139	$—	$144	$—	$144
Derivative assets - NUG contracts[1]	—	—	1	1	—	—	4	4
Equity securities[2]	—	—	—	—	30	—	—	30
Foreign government debt securities	—	2	—	2	—	—	—	—
U.S. government debt securities	—	8	—	8	—	2	—	2
U.S. state debt securities	—	230	—	230	—	219	—	219
Other[3]	—	48	—	48	—	15	—	15
Total assets	—	427	1	428	30	380	4	414
Liabilities								
Derivative liabilities - NUG contracts[1]	—	—	(125)	(125)	—	—	(147)	(147)
Derivative liabilities - LCAPP contracts[1]	—	—	(142)	(142)	—	—	—	—
Total liabilities	—	—	(267)	(267)	—	—	(147)	(147)
Net assets (liabilities)[4]	$—	$427	$(266)	$161	$30	$380	$(143)	$267

(1) NUG and LCAPP contracts are subject to regulatory accounting treatment and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $1 million and $2 million as of September 30, 2012 and December 31, 2011 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 NUG and LCAPP contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2012 and December 31, 2011:

	NUG Contracts(1)			LCAPP Contracts(1)		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(in millions)					
January 1, 2011 Balance	$6	$(233)	$(227)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	(2)	(11)	(13)	—	—	—
Purchases	—	—	—	—	—	—
Issuances	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	97	97	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
December 31, 2011 Balance	$4	$(147)	$(143)	$—	$—	$—
Realized gain (loss)	—	—	—	—	—	—
Unrealized gain (loss)	(3)	(17)	(20)	—	3	3
Purchases	—	—	—	—	(145)	(145)
Issues	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Settlements	—	39	39	—	—	—
Transfers in (out) of Level 3	—	—	—	—	—	—
September 30, 2012 Balance	$1	$(125)	$(124)	$—	$(142)	$(142)

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

Level 3 Quantitative Information

The following table provides quantitative information for NUG and LCAPP contracts held by JCP&L that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2012:

	Fair Value as of September 30, 2012 (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
NUG Contracts	$(124)	Model	Generation Electricity regional prices	95,000 to 1,324,000 $45.50 to $59.50	405,000 $54.10	MWH Dollars/MWH
LCAPP Contracts	$(142)	Model	Regional capacity prices	$158.60 to $197.30	$174.50	Dollars/MW-Day

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities.

FE and its subsidiaries periodically evaluate their investments for OTTI. They first consider their intent and ability to hold an equity investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FE and its subsidiaries consider their intent to hold the security, the likelihood that they will be required to sell the security before recovery of their cost basis and the likelihood of recovery of the security's entire amortized cost basis.

Unrealized gains applicable to the decommissioning trusts of FES and OE are recognized in OCI because fluctuations in fair value will eventually impact earnings while unrealized losses are recorded to earnings. The decommissioning trusts of JCP&L are subject to regulatory accounting. Net unrealized gains and losses are recorded as regulatory assets or liabilities because the difference between investments held in the trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

Available-For-Sale Securities

FES, OE and JCP&L hold debt and equity securities within their NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered available-for-sale securities at fair market value. FES, OE and JCP&L have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of September 30, 2012 and December 31, 2011:

	September 30, 2012[1]				December 31, 2011[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FirstEnergy	$1,529	$37	$—	$1,566	$1,980	$25	$—	$2,005
FES	500	8	—	508	1,012	13	—	1,025
OE	137	—	—	137	134	—	—	134
JCP&L	364	13	—	377	356	7	—	363
Equity securities								
FirstEnergy	$320	$46	$—	$366	$222	$36	$—	$258
FES	295	38	—	333	104	20	—	124
JCP&L	—	—	—	—	27	3	—	30

(1) Excludes short-term cash investments: FE Consolidated - $596 million; FES - $443 million; OE - $3 million; JCP&L - $51 million.

(2) Excludes short-term cash investments: FE Consolidated - $164 million; FES - $74 million; OE - $2 million; JCP&L - $19 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales and interest and dividend income for the three months and nine months ended September 30, 2012 and 2011 were as follows:

Three Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$1,751	$81	$(32)	$18
FES	1,059	60	(23)	10
OE	—	—	—	1
JCP&L	211	6	(2)	4
September 30, 2011	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**Interest and Dividend Income**
	(In millions)			
FirstEnergy	$1,974	$98	$(38)	$20
FES	1,100	52	(19)	9
OE	134	7	(1)	1
JCP&L	234	11	(4)	5

Nine Months Ended

September 30, 2012	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$2,133	$118	$(67)	$51
FES	1,167	85	(48)	27
OE	57	—	—	2
JCP&L	376	8	(4)	11
September 30, 2011	Sale Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
	(In millions)			
FirstEnergy	$3,678	$220	$(83)	$72
FES	1,613	74	(42)	41
OE	154	7	(1)	3
JCP&L	610	37	(10)	13

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains and approximate fair values of investments in held-to-maturity securities as of September 30, 2012 and December 31, 2011:

	September 30, 2012			December 31, 2011		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$210	$58	$268	$402	$50	$452
OE	148	33	181	163	21	184

Investments in emission allowances, employee benefit trusts and cost and equity method investments totaling $709 million as of September 30, 2012, and $693 million as of December 31, 2011, are excluded from the amounts reported above.

Notes Receivable

FES has a long-term note receivable of $4 million as of September 30, 2012 that matures in December 2013. Due to the short duration of this note, it is recorded at cost which approximates fair value.

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 in "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, as of September 30, 2012 and December 31, 2011:

	September 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$16,942	$19,677	$17,165	$19,320
FES	4,133	4,494	3,675	3,931
OE	1,157	1,500	1,157	1,434
JCP&L	1,753	2,092	1,777	2,080

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 listed above. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of September 30, 2012 and December 31, 2011.

8. 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 2018.

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 are 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 $13 million and $19 million as of September 30, 2012 and December 31, 2011, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Reclassifications from AOCI into other operating expenses were $2 million and less than $1 million of income during the three months ended September 30, 2012 and 2011, respectively, and $6 million of income and $18 million of loss during the nine months ended September 30, 2012 and 2011, respectively. Approximately $8 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. As of September 30, 2012, no forward starting swap agreements accounted for as a cash flow hedge were outstanding. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $72 million as of September 30, 2012. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months. Reclassifications from AOCI into interest expense totaled $2 million and $3 million during the three months ended September 30, 2012 and 2011, respectively, and $7 million and $9 million during the nine months ended September 30, 2012 and 2011, respectively.

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 September 30, 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 $85 million as of September 30, 2012. Based on current estimates, approximately $23 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest

expense totaled approximately $6 million and $5 million during the three months ended September 30, 2012 and 2011, respectively, and $17 million and $16 million during the nine months ended September 30, 2012 and 2011.

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 peaking units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts.

As of September 30, 2012, FirstEnergy's net asset position under commodity derivative contracts was $83 million, which related to FES and AE Supply positions. Under these commodity derivative contracts, FES posted $33 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $38 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 September 30, 2012, an adverse 10% change in commodity prices would decrease net income by approximately $18 million during the next twelve months.

Interest Rate Swaps

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were considered economic hedges, protecting against the risk of increases in future interest payments resulting from increases in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Changes in fair value of the forward starting swap agreements were recorded in net income on a market-to-market basis. In the second quarter of 2012, FirstEnergy executed a total of $1.6 billion forward starting swap agreements expiring December 31, 2013, with sixteen separate counterparties, in order to lock in interest rates on planned debt issuances, which includes refinancings. In August 2012, FirstEnergy terminated all of the forward starting swap agreements that were executed in the second quarter, resulting in a net gain, recorded as a reduction to interest expense, and cash proceeds of approximately $6 million.

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. During the second quarter of 2012, JCP&L began to account for these contracts as derivatives as a result of the generators clearing the 2015/2016 PJM RPM capacity auction. 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

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 FirstEnergy's unregulated subsidiaries are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's regulated subsidiaries 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.

The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets:
Derivatives not designated as hedging instruments:

Derivative Assets	Fair Value September 30, 2012 (In millions)	December 31, 2011	Derivative Liabilities	Fair Value September 30, 2012 (In millions)	December 31, 2011
Power Contracts			Power Contracts		
Current Assets	$178	$185	Current Liabilities	$(146)	$(196)
Noncurrent Assets	79	79	Noncurrent Liabilities	(31)	(51)
FTRs			FTRs		
Current Assets	7	1	Current Liabilities	(9)	(22)
Noncurrent Assets	—	—	Noncurrent Liabilities	(2)	(1)
NUGs	18	56	NUGs	(300)	(349)
LCAPP	—	—	LCAPP	(142)	—
Other Current Assets	3	—	Other Current Liabilities	—	—
	$285	$321		$(630)	$(619)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of September 30, 2012:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	33	38	(5)	MWH
FTRs	67	—	67	MWH
NUGs	16	—	16	MWH
LCAPP	408	—	408	MW
Natural Gas	16	—	16	BTUs

The effect of derivative instruments on the Consolidated Statements of Income during the three months and nine months ended September 30, 2012 and 2011, are summarized in the following tables:

	Three Months Ended September 30				
	Power Contracts	FTRs	Interest Rate Swaps	Other	Total
	(In millions)				
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$(2)	$—	$—	$—	$(2)
2011					
Gain (Loss) Recognized in AOCI (Effective Portion)	$—	$—	$—	$—	$—
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain (Loss) Recognized in:					
Other Operating Expense	$7	$(5)	$—	$—	$2
Interest Expense	—	—	20	—	20
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(27)	$—	$—	$—	$(27)
Revenues	46	6	—	—	52
Other Operating Expense	—	(10)	—	—	(10)
Fuel Expense	—	—	—	3	3
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$27	$—	$—	$—	$27
Revenues	3	—	—	—	3
Other Operating Expense	(11)	(9)	1	—	(19)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(5)	$—	$—	$—	$(5)
Revenues	(39)	20	(1)	—	(20)
Other Operating Expense	—	(22)	—	—	(22)

	Nine Months Ended September 30				
	Power Contracts (In millions)	FTRs	Interest Rate Swaps	Other	Total
Derivatives in a Hedging Relationship					
2012					
Loss Recognized in AOCI (Effective Portion)	$(6)	$—	$—	$—	$(6)
2011					
Gain Recognized in AOCI (Effective Portion)	$4	$—	$1	$—	$5
Effective Gain (Loss) Reclassified to:					
Purchased Power Expense	16	—	—	—	16
Revenues	(12)	—	—	—	(12)
Derivatives Not in a Hedging Relationship					
2012					
Unrealized Gain Recognized in:					
Other Operating Expense	$69	$12	$—	$3	$84
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(248)	$—	$—	$—	$(248)
Revenues	260	18	—	—	278
Other Operating Expense	—	(51)	—	—	(51)
Fuel Expense	—	—	—	2	2
Interest Expense	—	—	6	—	6
2011					
Unrealized Gain (Loss) Recognized in:					
Purchased Power Expense	$88	$—	$—	$—	$88
Revenues	(1)	—	—	—	(1)
Other Operating Expense	(65)	2	2	—	(61)
Realized Gain (Loss) Reclassified to:					
Purchased Power Expense	$(41)	$—	$—	$—	$(41)
Revenues	(69)	36	(2)	—	(35)
Other Operating Expense	—	(77)	—	—	(77)

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three and nine months ended September 30, 2012 and 2011, are summarized in the following tables:

	Three Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Gain (Loss) on Derivative Instrument	$(50)	$3	$—	$—	$(47)
Realized Gain (Loss) on Derivative Instrument	61	—	(1)	—	60
2011					
Unrealized Loss on Derivative Instrument	$(89)	$—	$(3)	$—	$(92)
Realized Gain (Loss) on Derivative Instrument	53	—	(3)	—	50

	Nine Months Ended September 30				
	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Derivatives Not in a Hedging Relationship with Regulatory Offset					
2012					
Unrealized Loss on Derivative Instrument	$(183)	$(142)	$—	$—	$(325)
Realized Gain on Derivative Instrument	194	—	7	—	201
2011					
Unrealized Loss on Derivative Instrument	$(325)	$—	$—	$—	$(325)
Realized Gain (Loss) on Derivative Instrument	187	—	(4)	(10)	173

The following table provides 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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30				
Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Outstanding net asset (liability) as of July 1, 2012	$(293)	$(145)	$—	$—	$(438)
Additions/Change in value of existing contracts	(50)	3	—	—	(47)
Settled contracts	61	—	(1)	—	60
Outstanding net asset (liability) as of September 30, 2012	$(282)	$(142)	$(1)	$—	$(425)
Outstanding net asset (liability) as of July 1, 2011	$(447)	$—	$2	$—	$(445)
Additions/Change in value of existing contracts	(89)	—	(3)	—	(92)

Settled contracts	53	—	(3)	—	50
Outstanding net asset (liability) as of September 30, 2011	$(483)	$—	$(4)	$—	$(487)

Derivatives Not in a Hedging Relationship with Regulatory Offset[1]	Nine Months Ended September 30 NUGs	LCAPP	Regulated FTRs	Other	Total
	(In millions)				
Outstanding net asset (liability) as of January 1, 2012	$(293)	$—	$(8)	$—	$(301)
Additions/Change in value of existing contracts	(183)	(142)	—	—	(325)
Settled contracts	194	—	7	—	201
Outstanding net asset (liability) as of September 30, 2012	$(282)	$(142)	$(1)	$—	$(425)
Outstanding net asset (liability) as of January 1, 2011	$(345)	$—	$—	$10	$(335)
Additions/Change in value of existing contracts	(325)	—	—	—	(325)
Settled contracts	187	—	(4)	(10)	173
Outstanding net asset (liability) as of September 30, 2011	$(483)	$—	$(4)	$—	$(487)

(1) Changes in the fair value of certain contracts are deferred for future recovery from (or credited to) customers.

9. 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.

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. The settlements with respect to residential SOS for PE customers expire on December 31, 2012, but by statute service will continue in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential service have expired but, 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. Expenditures were estimated to be approximately $101 million for the PE programs for the period of 2009 to 2015 and would be recovered over that six-year period. 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. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan that includes additional and improved programs for the period 2012-2014. The plan is expected to cost approximately $66 million over the three-year period. On December 22, 2011, the MDPSC issued an order approving PE's plan with various modifications and follow-up assignments.

Pursuant to a bill passed by the Maryland legislature, the MDPSC proposed rules, based on the product of a working group of utilities, regulators and other interested stakeholders, 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 bill requires that the MDPSC consider cost-effectiveness, and provides that the MDPSC may adopt different standards for different utilities based on such factors as system design and existing infrastructure, geography, and customer density. Beginning in July 2013, the MDPSC is required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. Further comments were filed regarding the proposed rules on March 26, 2012, and at a hearing on April 17, 2012, the MDPSC approved re-publication of the rules as final.

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 on September 13 and 14, 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 that the MDPSC approved on April 17, 2012, and 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. The panel's report has been referred to the MDPSC for action.

NEW JERSEY

JCP&L currently provides BGS for retail customers that 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. The most recent BGS auction results, for supply that commenced on June 1, 2012, were approved by the NJBPU on February 9, 2012.

On September 8, 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 the Company 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. Due to Hurricane Sandy, JCP&L requested an extension and will file a base rate case using a historic 2011 test year by December 1, 2012.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held to solicit comments regarding the state of preparedness and responsiveness of the EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 31, 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. The NJBPU solicited written comments on the report from stakeholders to be submitted by September 20, 2012, and JCP&L submitted written comments on that date. The NJBPU has not specified the action that will be taken as a result of information obtained through this process.

OHIO

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

- Generation supplied through a CBP commencing June 1, 2011;
- 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 dependent on the outcome of certain PJM proceedings, 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.

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;
- Providing Percentage of Income Payment Plan customers with a 6 percent generation rate discount;
- Continuing to provide power to shopping and to non-shopping customers as part of the 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 October 2012 and January 2013, to mitigate any potential price spikes for FirstEnergy Ohio utility customers who do not switch to a competitive generation supplier; and

- Extending the recovery period for costs associated with purchasing RECs mandated by SB 221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all FirstEnergy Ohio non-shopping utility customers 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. Utilities were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

In December 2009, the Ohio Companies filed their three-year portfolio plan, as required by SB221, seeking approval for the programs they intended to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. In March 2011, the PUCO issued an Opinion and Order generally approving the Ohio Companies' 2010-2012 portfolio plan which provides for recovery of all costs associated with the programs, including lost revenues. The Ohio Companies have implemented those programs included in the plan. Failure to comply with the benchmarks or to obtain such an amendment may subject the Ohio Companies to an assessment of a penalty by the PUCO.

The Ohio Companies had filed applications for rehearing regarding portions of the PUCO's decision related to the Ohio Companies' three-year portfolio plan, which was later denied by the PUCO and the subsequent appeal was dismissed by the Supreme Court of Ohio. 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. Hearings were held the week of October 22, 2012.

Additionally, under SB221, electric utilities and electric service companies are required to serve part of their load in 2011 from renewable energy resources equivalent to 1.00% of the average of the KWH they served in 2008-2010; in 2012 from renewable energy resources equivalent to 1.50% of the average of the KWH they served in 2009-2011; and in 2013 from renewable energy resources equivalent to 2.00% of the average of the KWH they served in 2010-2012. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RECs acquired through these two 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 beyond. On September 20, 2011 the PUCO opened a new docket to review the Ohio Companies' alternative energy recovery rider. 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. The PUCO has set this matter for hearing on February 19, 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 have achieved their in-state solar compliance requirements for 2012. The Ohio companies are in the midst of 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.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire 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 DSP 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 made a compliance filing on September 6, 2012, seeking finalization of their procurement and rate design plans, and the PPUC issued a Secretarial Letter on November 8, 2012 approving the compliance filing. The PPUC entered an order on September 27, 2012, disposing of the Petitions for Reconsideration or Clarification filed by the Pennsylvania Companies and other parties. The Pennsylvania Companies were granted an extension to file revised proposals on the retail market enhancements by November 14, 2012.

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 began to refund those amounts to customers in January 2011, and the refunds are continuing over a 29-month period until the full amounts previously recovered for marginal transmission losses are refunded. 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. ME and PN filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which was denied on February 28, 2012, and ME and PN also filed a complaint seeking relief in the U.S. District Court for the Eastern District of Pennsylvania, which was subsequently amended. The PPUC filed a Motion to Dismiss the amended complaint on September 15, 2011, to which ME and PN responded. On September 26, 2012, United States District Court Judge Gardner entered an order dismissing the PPUC's motion to dismiss without prejudice. On June 27, 2012, ME and PN filed a Petition for Writ of Certiorari with the Supreme Court of the United States. On October 9, 2012, the Supreme Court denied that petition. Accordingly, ME and PN intend to pursue their claims in the proceedings that are pending in the U.S. District Court (E.D. PA).

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 upon utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a final 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 has been unable to provide final results because several customers are still accumulating necessary documentation for projects that may qualify for inclusion in the final results. Preliminary numbers indicate that WP did not achieve its 2011 benchmark and it is not known at this time whether WP will be subject to a fine for failure to achieve the benchmark. WP could be subject to a statutory penalty of up to $20 million and is unable to predict the outcome of this matter.

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 1, 2012, a phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. A hearing on the level of the Pennsylvania Companies' respective Phase II energy efficiency targets as established by the PPUC was held on October 19, 2012. 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.

In addition, Act 129 required utilities to file a SMIP with the PPUC. In light of the significant expenditures that would be associated with its smart meter deployment plans and related infrastructure upgrades, as well as its evaluation of recent PPUC decisions approving less-rapid deployment proposals by other utilities, WP re-evaluated its Act 129 compliance strategy, including both its plans with respect to its previously approved smart meter deployment plan and certain smart meter dependent aspects of the EE&C Plan. WP proposed to decelerate its previously contemplated smart meter deployment schedule and to target the installation of approximately 25,000 smart meters in support of its EE&C Plan, based on customer requests, by mid-2012. WP also proposed to take advantage of the 30-month grace period authorized by the PPUC to continue WP's efforts to re-evaluate full-scale smart meter deployment plans. WP would be permitted to recover certain previously incurred and anticipated smart-meter related expenditures through a levelized customer surcharge, with certain expenditures amortized over a ten-year period. A joint settlement with all parties based on these terms, with one party retaining the ability to challenge the recovery of amounts spent on WP's original SMIP, was approved by the PPUC on June 30, 2011. Additionally, WP would be permitted to seek recovery of certain other costs as part of its revised SMIP that it currently intends to file by the end of 2012, or in a future base distribution rate case. The deadline for the Pennsylvania Companies to file their smart meter deployment plan is December 31, 2012.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market will 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. Following the issuance of a Tentative Order and comments filed by numerous parties, the PPUC entered a final order on December 16, 2011, providing recommendations for components to be included in upcoming DSPs, including: the duration of the programs and the length of associated energy contracts; a customer referral program; a retail opt-in auction; time-of-use rate options provided through contracts with EGSs; and periodic rate adjustments. Following the issuance of a Tentative Order and comments filed by various parties, the PPUC entered a final order on March 2, 2012 outlining an intermediate work plan. Several suggested models for long-range default service have been presented and were the topic of a March 2012 en banc hearing. On September 27, 2012, the PPUC issued a Secretarial Letter and an "RMI End State Proposal" discussion document. PPUC staff hosted a conference call on October 17, 2012, and a Tentative Order was entered by the PPUC on November 8, 2012, seeking comments, that are due within 30 days, regarding the end state of default service and related issues.

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 electric 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 ME, PN, Penn, WP and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES, ME, PN, Penn and WP 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 April 26, 2012, on the proposed rulemaking, 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

In April 2010, MP and PE filed with the WVPSC a Joint Stipulation and Agreement of Settlement reached with the other parties in a proceeding for an annual increase in retail rates 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.

The WVPSC approved the Joint Petition and Agreement of Settlement in June 2010.

In February 2011, MP and PE filed a petition with the WVPSC seeking an order declaring that MP owns all alternative and 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, have participated in the case in opposition to the petition. The WVPSC issued an order on November 22, 2011, granting ownership of all RECs produced by the facilities to MP, and holding that an electric utility that purchases electric energy and capacity under an electric power purchase agreement with a Qualifying Facility formed under PURPA owns the RECs associated with that purchase. The West Virginia Supreme Court issued an Order on June 11, 2012, upholding the WVPSC's decision. The City of New Martinsville and Morgantown Energy Associates filed complaints at FERC alleging the WVPSC order violated PURPA and requested that FERC initiate an enforcement action. On April 24, 2012, the FERC ruled that the FERC-jurisdictional contracts are intended to pay only for electric energy and capacity (and not for RECs), and that state law controlled on the issues of determining which entity owns RECs and how they are transferred between entities. The FERC declined to act on the complaints and instead noted that the City of New

Martinsville and Morgantown Energy Associates could file complaints in the U.S. District Court. FERC also noted there may be language in the WVPSC order that is inconsistent with PURPA. MP filed for rehearing of the FERC's order taking the position that the WVPSC order is consistent with PURPA, which was denied by FERC on September 20, 2012. The City of New Martinsville filed a complaint in the U.S. District Court on June 4, 2012, alleging that the WVPSC order violates PURPA.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated by September 1, 2012.

The WVPSC has proceedings for each West Virginia electric utility to establish reliability targets for distribution performance. The parties entered into a settlement in September 2012 resolving all issues and establishing performance targets with more stringent targets beginning in 2014. The settlement is under review by the WVPSC.

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.

The West Virginia ENEC fuel case was filed by MP and PE at the WVPSC in August 2012 with a projected over-recovery of approximately $66 million under current rates for the next year, January 1, 2013 through December 31, 2013. MP and PE proposed no change in overall rates on January 1, 2013; however, MP and PE proposed establishing a separate regulatory liability for the difference between the recommended 2013 ENEC rates and the current ENEC rates. This estimated $66 million liability would be used to offset the rate relief MP and PE will seek in a filing later this year to become effective with the completion of a proposed generation resource transaction, which MP and PE will propose to complete by mid-2013. Discovery in the ENEC proceeding is underway and a hearing is expected in December 2012.

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 plan to file a Petition for Approval of a Generation Resource Transaction with the WVPSC in November 2012 that involves 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 what we believe to be a cost-effective plan to assist MP in meeting its energy and capacity obligations with its own generation resources, eliminating the need to make additional 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 increase due to an increase in annual load growth of approximately 1.4%.

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, FGCO, 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. The financial impact of complying with future new or amended standards cannot be determined at this time; however, 2005 amendments to the FPA provide that all prudent costs incurred to comply with the future reliability standards be recovered in rates. Any future 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.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. On March 22, 2012, NERC concluded the investigation of the matter and forwarded it to NCEA for further review. NCEA is currently evaluating the findings of the investigation. JCP&L expects the matter to be resolved for an immaterial amount.

During September 2012, RFC performed a routine compliance audit of certain parts of FirstEnergy's bulk-power systems and generally found the audited systems and processes to be in full compliance with all the audited reliability standards.

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" 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. This debate is framed by regulatory and court decisions. In 2007, 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. Subsequently, numerous parties filed responsive comments or studies on May 28, 2010 and reply comments on June 28, 2010. 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 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. FirstEnergy's request for rehearing remains pending before FERC.

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 (or usage based) and 50% postage stamp (or socialization) to be effective for RTEP projects approved by the PJM Board on and after the effective date of the compliance filing. The filing is pending before FERC. Filings to demonstrate compliance with the interregional cost allocation principles of the order must be submitted to FERC by April 2013.

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 which dispute are discussed below in the "MISO Multi-Value Project Rule Proposal." In addition, FERC denied certain exit fees of ATSI's transmission rate 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. Finally, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to loads 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. ATSI is considering whether to appeal FERC's ruling on the "legacy RTEP" issue. FirstEnergy has also appealed the issue of legacy RTEP to the Seventh Circuit Court of Appeals. Although there can be no assurance, success in the appeal could terminate the ATSI zone's responsibility for legacy RTEP charges.

ATSI's filings and requests for rehearing on certain of these matters, as well as the pleadings submitted by parties that oppose ATSI's position are currently pending before FERC. Finally, on August 22, 2012, FERC approved a negotiated agreement that requires ATSI to pay a one-time charge of $1.8 million for long term firm transmission rights that, according to the MISO, were payable upon ATSI's exit.

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 projects that were approved by MISO's Board prior to the June 1, 2011 effective date of FirstEnergy's integration into PJM would continue to 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.

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 that assert 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 classes: litigation related to the MISO's generic MVP cost allocation proposal; and litigation related to the MISO's "Schedule 39" tariff that purports to charge the MVP costs against ATSI.

On October 31, 2011, FirstEnergy filed a Petition of Review of certain of the FERC's orders that address the generic MVP tariffs 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 cases were consolidated for briefing and disposition in the U.S. Court of Appeals for the Seventh Circuit with briefs due from the parties through 2012 and oral argument to be scheduled in 2013.

In February 2012, FERC accepted the MISO's proposed Schedule 39 tariff, subject to hearings and potential refund of MVP charges to ATSI. MISO's Schedule 39 tariff is the vehicle through which the MISO plans to charge the Michigan Thumb Project costs 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 will start in April 2013.

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

PJM Underfunding FTR Complaint

On December 28, 2011, FES and AE Supply filed a complaint with FERC against PJM challenging the ongoing underfunding of FTR contracts, which exist to hedge against transmission congestion in the day-ahead markets. The underfunding is a result of PJM's practice of using the funds that are intended to pay the holders of FTR contracts to pay instead for congestion costs that occur in the real time markets. Underfunding of the FTR contracts resulted in losses of approximately $35 million ($0.5 million - FES; $34.5 million - AE Supply) in the 2010-2011 Delivery Year. Losses for the 2011-2012 Delivery Year are estimated to be approximately $11.5 million ($11.4 million - FES; $0.1 million - AE Supply). On January 13, 2012, PJM filed comments describing changes to the PJM tariff that, if adopted, should remedy the underfunding issue. On March 2, 2012, FERC dismissed the complaint without prejudice, pending PJM's publication for stakeholder review and discussion, a report on the causes of the FTR underfunding and potential improvements, including modeling, which could be made to minimize the revenue inadequacy. On March 30, 2012, FES and AE Supply requested rehearing and reconsideration of the March 2, 2012 order. On July 19, 2012, FERC issued its Order on Rehearing and again dismissed FirstEnergy's complaint without prejudice. FERC noted PJM's ongoing stakeholder process and directed that if the issues were not addressed in that process FirstEnergy could file its complaint again.

FTR Allocation Complaint

On March 26, 2012, FES and AE Supply filed a complaint with FERC against PJM challenging PJM's FTR allocation rules. PJM allocates FTRs to LSEs in an annual allocation process, up to each LSE's peak load, based on the expected transmission capability for the upcoming planning year. If a transmission facility is scheduled to be out of service for a significant part of the year, it can result in LSEs' FTR allocations being reduced in the annual allocation. When these transmission facilities return to service during the year, PJM will create monthly FTRs to reflect the increased transmission capability during that month. However, instead of allocating these new monthly FTRs to the LSEs that were unable to obtain their full allocation of FTRs in the annual allocation process, PJM's rules instead require PJM to auction off these new monthly FTRs in the market. The complaint seeks a change to the PJM rules such that the new FTRs created each month by transmission lines returning to service would first be allocated to those LSEs that were denied a full allocation of their FTR entitlement in the annual allocation process before they are auctioned off in the market. On April 16, 2012, PJM filed its answer to the complaint. Exelon Corporation filed a protest, and several other parties filed comments. On July 11, 2012, FERC issued its Order Granting Complaint and Requiring a Compliance Filing. In the order, FERC agreed with FirstEnergy's description of the issues and with FirstEnergy's proposed changes to PJM's rules, and FERC directed PJM to submit a compliance filing within 60 days to implement the changes in the rules. On September 10, 2012, PJM submitted the compliance filing. On October 17, 2012, FERC accepted the PJM compliance filing, resolving this matter.

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 United States Court of Appeals for the Ninth Circuit in 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. In March 2010, the FERC ALJ assigned to the case entered an opinion that granted the motions to dismiss filed by AE Supply and other sellers and dismissed the claims of the California Parties. On May 4, 2011, FERC affirmed the judge's ruling. On June 3, 2011, the California parties requested rehearing of the May 4, 2011 order. By Order issued June 13, 2012, FERC denied the request for rehearing.

On June 20, 2012, the California Parties appealed the FERC's decision back to the Ninth Circuit Court of Appeals. On July 19, 2012, the Ninth Circuit Court of Appeals issued an order declining to consolidate the appeal with other pending appeals regarding California refund claims, suspending briefing, and directing interested parties to intervene by August 31, 2012. AE Supply filed an intervention on August 28, 2012. On September 6, 2012, the Ninth Circuit issued an order granting AE Supply's intervention and continuing the suspension of the briefing schedule ordered on July 19, 2012. The timing of further action by the Ninth Circuit is unknown.

In June 2009, the California Attorney General, on behalf of certain California parties, filed a second 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 additional complaint. AE Supply filed a motion to dismiss this second complaint, which was granted by FERC on May 24, 2011. On June 23, 2011, the California Attorney General requested rehearing of the May 24, 2011 order. By Order issued June 13, 2012, that request for rehearing also was denied. On June 20, 2012, the California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. In addition, on July 13, 2012, the California Attorney General requested rehearing of the June 13, 2012 order. On July 19, 2012, the Ninth Circuit consolidated the June 20, 2012 appeal with other pending appeals related to California refund claims, referred the case to the Circuit Mediator, and stayed the proceedings pending further order. On August 7, 2012, FERC rejected the California Attorney General's July 13, 2012 request for rehearing. On August 16, 2012, the California Attorney General appealed the August 7, 2012 order to the Ninth Circuit. On August 29, 2012, the Ninth Circuit consolidated the August 16, 2012 appeal with the aforementioned cases and continued the stay 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 officially canceled the project, which it had originally suspended in February 2011. All applications for authorization to construct the project filed with state commissions have been withdrawn. As a result, approximately $62 million and $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, these companies requested authorization from FERC to recover these costs associated with the project with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO Membership) from PJM customers over the next 5 years. Several parties have protested the request and a FERC decision is pending.

On September 20, 2012, FERC set for hearing formal challenges to the PATH formula rate annual updates submitted in June 2010 and June 2011. These challenges seek a disallowance of approximately $6.6 million in costs for the project. Settlement judge procedures are pending. FirstEnergy cannot predict the outcome of either of the above 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, a subsidiary of Public Service Enterprise Group, 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 existing license expires on February 28, 2013.

In February 2011, JCP&L and PSEG filed a joint application with FERC to renew the license for an additional forty years. The companies are pursuing relicensure through FERC's ILP. Under the ILP, FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunities for intervention and protests by affected third parties. FERC may hold hearings during the five-year ILP licensure process. FirstEnergy expects FERC to issue the new license before February 28, 2013. To the extent however that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended yearly as necessary to permit FERC to issue the new license.

Seneca

The Seneca Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania owned and operated by FGCO. FGCO 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, FGCO initiated the relicensing process by filing its notice of intent to relicense and related documents in the license docket.

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. 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. Nonetheless, FGCO believes it is entitled to a statutory “incumbent preference” under Section 15.

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 October 11, 2011, FERC Staff issued a letter order that addressed the Revised Study Plans. In the order, FERC Staff approved FirstEnergy's Revised Study Plan, subject to a finding that the Project is located on “aboriginal lands” of the Seneca Nation. Based on this finding, FERC Staff directed FirstEnergy to consult with the Seneca Nation and other parties about the data set, methodology and modeling of the hydrological impacts of project operations. In March of 2012, FirstEnergy hosted a meeting as part of the consultation process. In that meeting, FirstEnergy reviewed its proposed methodology for conducting the hydrological impacts study and answered questions from third parties about the methodology. On April 11, 2012, the Seneca Nation and other parties filed comments on the proposed hydrologic impacts study, the study processes, including the discrete hydrological impacts study, which study will extend through approximately November 2013.

FirstEnergy cannot predict the outcome of this matter or estimate the possible loss or range of loss.

MISO Capacity Portability

On June 11, 2012, the 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 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 on August 10, 2012, and reply comments on August 27, 2012. 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 the prices at which those auctions would clear.

10. 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 September 30, 2012, outstanding guarantees and other assurances aggregated approximately $4.1 billion, consisting of parental guarantees ($0.9 billion), subsidiaries' guarantees ($2.4 billion) and other guarantees ($0.7 billion).

FES' debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, and FES guarantees the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO, and NGC would have claims against each of FES, FGCO and NGC, regardless of whether their primary obligor is FES, FGCO or NGC.

COLLATERAL AND CONTINGENT-RELATED FEATURES

As part of the normal course of business, FirstEnergy 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 FirstEnergy or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FirstEnergy'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 FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on FES' and AE Supply's power portfolio exposure as of September 30, 2012, FES has posted collateral of $73 million. The Regulated Distribution segment has posted collateral of $21 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 and lower, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of September 30, 2012:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$397	$6	$42	$445
BB+/Ba1 Credit Ratings	$450	$6	$61	$517
Full impact of credit contingent contractual obligations	$671	$72	$76	$819

Excluded above are potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Segment. As of September 30, 2012, 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 $40 million and $11 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a new 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, of 4% through December 31, 2012, 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, 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 FGCO 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. FGCO 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 preconstruction 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. The Court dismissed New Jersey's and Connecticut's claims for injunctive relief against ME, but denied ME's motion to dismiss the claims for civil penalties. On July 27, 2012, ME filed a motion for summary judgment on plaintiff's remaining claims for civil penalties. The parties dispute the scope of ME's indemnity obligation to and from Sithe Energy. In February 2012, GenOn announced its plans to retire 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 July 27, 2012, FirstEnergy filed a motion for summary judgment arguing the Plaintiff's remaining claims for civil penalties are barred by the statute of limitations. On November 1, 2012, the other defendants and the plaintiffs filed motions for summary judgment regarding various claims. FirstEnergy 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 January 2009, the EPA issued a 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, JCP&L and PN, as former owners of the facilities, are 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 between 1991 to 1994 without preconstruction 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. 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 and their opening appellate brief is due November 14, 2012. 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. FGCO 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 a 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, EPA issued another CAA section 114 request 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 ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, FGCO's and AE Supply's future cost of compliance may be substantial and changes to FirstEnergy's 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. 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 estimated to be approximately $975 million and other changes to FirstEnergy's operations may result.

On January 26, 2012 and February 8, 2012, FGCO, MP and AE Supply announced the deactivation by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. 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 10, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. On July 16, 2012, FGCO and ATSI filed an application with FERC for authorization to transfer from FGCO to ATSI certain assets associated with Eastlake Units 1-5 and Lakeshore Unit 18 for conversion to synchronous condensers by ATSI for transmission reliability purposes as directed by PJM. Upon FERC approval, it is expected that the assets will be transferred in staggered closings when the units are no longer needed for RMR purposes. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island have been deactivated. During the nine months ended September 30, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

On March 9, 2012, to assist the WVPSC with inquiries from public officials and the public, MP provided information to the WVPSC in the form of a closed entry filing in the ENEC case related to the plant deactivations. The WVPSC issued a final order on July 13, 2012, finding that FirstEnergy's decision to deactivate the Albright, Rivesville and Willow Island plants was reasonable and concluded that the plants could be deactivated by September 1, 2012.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, in June 2009. Certain states, primarily the northeastern states participating in the RGGI and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required FirstEnergy to measure and report 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 preconstruction 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.

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 from 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. A December 2011 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.

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 July 2012, the period for finalizing the Section 316(b) regulation was extended to July 27, 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.

In April 2011, the U.S. Attorney's Office in Cleveland, Ohio advised FGCO that it is no longer considering prosecution under the CWA and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. On June 5, 2012, FirstEnergy executed a tolling agreement with the EPA extending the statute of limitations for civil liability claims for those petroleum spills to January 31, 2013. FGCO does not anticipate any losses resulting from this matter to be material.

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including TDS and sulfate concentrations in the Monongahela River, on new and modified sources, including the scrubber project at the coal-fired Hatfield's Ferry Plant. These criteria are reflected in the NPDES water discharge permit issued by PA DEP for that project. In January 2009, AE Supply appealed the PA DEP's permitting decision to the EHB, due to estimated costs in excess of $150 million in order to install technology to meet TDS and sulfate limits in the NPDES permit. Environmental Integrity Project and Citizens Coal Council also appealed the NPDES permit seeking to impose more stringent technology-based effluent limitations. The EHB dismissed these appeals on August 29, 2012, after a settlement in the form of a Consent Decree was entered by the Commonwealth Court of Pennsylvania on August 16, 2012, resolving the disputes concerning the Hatfield's Ferry Plant NPDES permit, including elimination of the TDS limit and deferring the lower sulphate limits until July 2018.

The PA DEP recommended, and in August 2010, the Pennsylvania Environmental Quality Board issued, a final rule imposing end-of-pipe TDS effluent limitations. FirstEnergy could incur significant costs for additional control equipment to meet the requirements of this rule, although its provisions do not apply to electric generating units until the end of 2018, and then would apply only if the EPA has not promulgated TDS effluent limitation guidelines applicable to such units.

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. PA DEP's goal is to submit a final water quality standards regulation, incorporating the sulfate impairment designation for EPA approval by May 2013. PA DEP will then need to develop a TMDL limit for the river, a process that will take approximately five years. Based on the stringency of the TMDL, FirstEnergy may incur significant costs to reduce sulfate discharges into the Monongahela River from the coal-fired Hatfield's Ferry and Mitchell Plants in Pennsylvania and the coal-fired Fort Martin Plant in West Virginia.

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 May 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club filed a CWA citizen suit in the U.S. District Court for the Northern District of West Virginia alleging violations of arsenic limits in the NPDES water discharge permit for the fly ash impoundments at the Albright Station seeking unspecified civil penalties and injunctive relief. In June 2011, the West Virginia Highlands Conservancy, the West Virginia Rivers Coalition, and the Sierra Club served a 60-day Notice of Intent required prior to filing a citizen suit under the CWA for alleged failure to obtain a permit to construct the fly ash impoundments at the Albright Plant. MP filed an answer on July 11, 2011, and a motion to stay the proceedings on July 13, 2011. In April 2012, the parties reached a settlement to resolve these CWA citizen suit claims for an immaterial amount. On August 14, 2012, a Consent Decree was entered by the Court resolving these claims. MP is currently seeking relief from the arsenic limits through a WVDEP agency review.

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 July 27, 2012, the PA DEP filed a complaint against FGCO 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 FGCO to resolve those claims. The proposed Consent Decree, if entered by the court, requires FGCO 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 proposed Consent Decree would also require payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. The Bruce Mansfield Plant is pursuing several options for disposal of CCB following December 31, 2016.

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 September 30, 2012, 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 $123 million (including $86 million applicable to JCP&L) have been accrued through September 30, 2012. Included in the total are accrued liabilities of approximately $79 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 September 30, 2012, FirstEnergy had approximately $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 guarantee, 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. FirstEnergy Corp. currently maintains a $95 million parental guaranty in support of the decommissioning of 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. By an order dated April 26, 2011, a 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 July 26, 2012, FENOC filed a motion for Summary Disposition on the remaining admitted contention on the SAMA analysis for Davis-Besse. On January 10, 2012, intervenors petitioned the ASLB for a new contention on the longitudinal cracking of the Davis-Besse shield building discussed below. The intervenors supplemented their petition for a contention on the shield building on multiple occasions. The ASLB scheduled a November 5 and 6, 2012 oral argument to consider FENOC's motion for summary disposition, the intervenors request for a new contention on the Shield Building.

On June 18 and 19, 2012, the intervenors in the Davis-Besse license renewal proceeding and other petitioners requested that the NRC suspends the issuance of final decisions in all pending reactor licensing proceedings as a result of the decision in the case of State of New York v. NRC, No. 11-1045. (D.C. Cir. June 8, 2012). In this case, the D.C. Circuit vacated the NRC's updated Waste Confidence Decision and its Temporary Storage Rule and remanded those rulemakings to the NRC for further consideration. FENOC and other Licensees opposed the suspension request. On July 9, 2012, the intervenors petitioned the ASLB for a new contention on the environmental impacts of temporary spent fuel storage by Davis-Besse due to the lack of a repository and the disposal of these wastes. By order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the D.C. Circuit decision and all pending contentions on this topic should be held in abeyance until further order. The NRC also directed that all licensing reviews and proceedings should continue to move forward. 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 proposed contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding.

On October 1, 2011, Davis-Besse was safely shut down for a scheduled outage to install a new reactor vessel head and complete other maintenance activities. The new reactor head, which replaced a head installed in 2002, enhances safety and reliability, and features control rod nozzles made of material less susceptible to cracking. On October 10, 2011, following opening of the building for installation of the new reactor head, a sub-surface hairline crack was identified in one of the exterior architectural elements on the shield building. These elements serve as architectural features and do not have structural significance. During investigation of the crack at the shield building opening, concrete samples and electronic testing found similar sub-surface hairline cracks in most of the building's architectural elements. FENOC's investigation also identified other indications. Included among them were sub-surface hairline cracks in the upper portion of the shield building (above elevation 780') and in the vicinity of the main steam line penetrations. A team of industry-recognized structural concrete experts and Davis-Besse engineers has determined these conditions do not affect the facility's structural integrity or safety.

On December 2, 2011, the NRC issued a CAL which concluded that FENOC provided "reasonable assurance that the shield building remains capable of performing its safety functions." The CAL imposed a number of commitments from FENOC, including, submitting a root cause evaluation and corrective actions to the NRC by February 28, 2012, and further evaluations of the shield building. On February 27, 2012, FENOC sent the root cause evaluation to the NRC. Finally, the CAL also stated that the NRC was still evaluating whether the current condition of the shield building conforms to the plant's licensing basis. On December 6, 2011, the Davis-Besse plant returned to service. On June 21, 2012, the NRC issued an Inspection Report that concluded that FENOC established a sufficient basis for the causes of the shield building laminar cracking.

By 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 will conduct several supplemental inspections, culminating in an inspection using Inspection Procedure 95002 to determine if the root cause and contributing causes of risk significant performance issues are understood, the extent of condition has been identified, whether safety culture contributed to the performance issues, and if FENOC's corrective actions are sufficient to address the causes and prevent recurrence. The NRC Staff began its 95002 inspection at the Perry plant on August 27, 2012. Additional adverse findings by the NRC could result in further inspection activities.

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.

On February 16, 2012, the NRC issued a request for information to the licensed operators of 11 nuclear power plants, including Beaver Valley Power Station Units 1 and 2, with respect to the modeling of fuel performance as it relates to "thermal conductivity degradation," which is the potential in higher burn up fuel for reduced capacity to transfer heat that could potentially change its performance during various accident scenarios, including loss of coolant accidents. The request for information indicated that this phenomenon has not been accounted for adequately in performance models for the fuel developed by the fuel manufacturer and that the NRC might consider imposing restrictions on reactor operating limits. On March 16, 2012, FENOC submitted its response to the NRC demonstrating that the NRC requirements are being met. FENOC also agreed to submit to the NRC revised large break loss of coolant accident analyses by December 15, 2016, that further consider the effects of fuel pellet thermal conductivity degradation.

On September 17, 2012, FENOC announced a plan to expand used nuclear fuel storage capacity at its two unit Beaver Valley Power Station. Under the plan, above-ground, airtight steel and concrete canisters will be installed to provide cooling, through natural air circulation, to used fuel assemblies. Initial installation will consist of six canisters and up to 47 additional canisters will be added as needed. Construction of the fuel storage system is scheduled to begin in fall 2012, with completion planned for 2014. Certain costs incurred by FirstEnergy for this project are expected to be reimbursable by the DOE under a January 2012 settlement. Due to a change in NRC regulations, FirstEnergy will be required to independently fund the radiological decommissioning of its independent spent fuel storage 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 will file a Petition for Allowance of Appeal with the Pennsylvania Supreme Court within 30 days. A ruling by the Supreme Court on whether it will hear the case is expected in the second quarter of 2013. AE Supply and MP intend to vigorously pursue this matter through appeal.

Other Legal Matters

In February 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount had been approved by the PUCO. In March 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction. The court granted the motion to dismiss and the plaintiffs appealed the decision to the Court of Appeals of Ohio. The Court of Appeals affirmed the dismissal of the Complaint by the Court of Common Pleas on all counts except for one relating to an allegation of fraud which it remanded to the trial court. The Companies timely filed a notice of appeal with the Supreme Court of Ohio on December 5, 2011, challenging this one aspect of the Court of Appeals opinion. The Supreme Court of Ohio heard arguments on the appeal in September, 2012.

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 9, Regulatory Matters to the Combined Notes to the 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 and 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.

Storm Cost Contingency

In late October 2012, FirstEnergy experienced unprecedented damage in its service territory as a result of Hurricane Sandy. Approximately 2.3 million customers were affected by outages in New Jersey, Pennsylvania, West Virginia, Ohio and Maryland. Nearly 20,000 professionals, including employees from FirstEnergy's Utilities and outside contractors and utility workers have worked to restore service to customers who lost power following the devastating storm. As of November 7, 2012, more than 95% of customers in Pennsylvania, Ohio, West Virginia and Maryland who were affected by the storm had electric service restored. In New Jersey, where the storm damage was most severe, nearly 1.2 million customers were affected by the storm. As of November 7, 2012, 85% of affected customers in New Jersey have been restored. Storm costs are expected to exceed $500 million, of which approximately 95% is expected to be capitalized or deferred for future recovery from customers. Final storm costs will be determined during the fourth quarter of 2012.

11. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FGCO completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully, unconditionally and irrevocably guaranteed all of FGCO’s obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, 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 for FGCO.

The Condensed Consolidating Statements of Income and Comprehensive Income for the three months and nine months ended

September 30, 2012 and 2011, Consolidating Balance Sheets as of September 30, 2012 and December 31, 2011, and Consolidating Statements of Cash Flows for the nine months ended September 30, 2012 and 2011, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC 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 September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,523	$617	$395	$(978)	$1,557
OPERATING EXPENSES:					
Fuel	—	248	55	—	303
Purchased power from affiliates	1,042	—	67	(978)	131
Purchased power from non-affiliates	499	—	—	—	499
Other operating expenses	130	79	122	12	343
Provision for depreciation	1	30	41	(1)	71
General taxes	20	10	5	—	35
Total operating expenses	1,692	367	290	(967)	1,382
OPERATING INCOME (LOSS)	(169)	250	105	(11)	175
OTHER INCOME (EXPENSE):					
Investment income	1	5	37	(5)	38
Miscellaneous income, including net income from equity investees	317	—	—	(316)	1
Interest expense — affiliates	(5)	(2)	(1)	5	(3)
Interest expense — other	(25)	(27)	(15)	16	(51)
Capitalized interest	—	1	8	—	9
Total other income (expense)	288	(23)	29	(300)	(6)
INCOME BEFORE INCOME TAXES	119	227	134	(311)	169
INCOME TAXES (BENEFITS)	18	(11)	59	2	68
NET INCOME	$101	$238	$75	$(313)	$101
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$101	$238	$75	$(313)	$101
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized loss on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available for sale securities	(2)	—	(1)	1	(2)
Other comprehensive loss	(9)	(4)	(1)	5	(9)
Income tax benefits on other comprehensive loss	(3)	(2)	—	2	(3)

Other comprehensive loss, net of tax	(6)	(2)	(1)	3	(6)
COMPREHENSIVE INCOME	$95	$236	$74	$(310)	$95

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

For the Nine Months Ended September 30, 2012	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$4,443	$1,795	$1,262	$(2,971)	$4,529
OPERATING EXPENSES:					
Fuel	—	824	154	—	978
Purchased power from affiliates	3,163	—	189	(2,971)	381
Purchased power from non-affiliates	1,420	—	—	—	1,420
Other operating expenses	313	271	410	37	1,031
Provision for depreciation	3	90	114	(4)	203
General taxes	60	28	16	—	104
Total operating expenses	4,959	1,213	883	(2,938)	4,117
OPERATING INCOME (LOSS)	(516)	582	379	(33)	412
OTHER INCOME (EXPENSE):					
Investment income	2	14	49	(15)	50
Miscellaneous income, including net income from equity investees	854	19	—	(848)	25
Interest expense — affiliates	(14)	(5)	(3)	15	(7)
Interest expense — other	(72)	(79)	(36)	47	(140)
Capitalized interest	—	3	24	—	27
Total other income (expense)	770	(48)	34	(801)	(45)
INCOME BEFORE INCOME TAXES	254	534	413	(834)	367
INCOME TAXES (BENEFITS)	32	(19)	124	8	145
NET INCOME	$222	$553	$289	$(842)	$222
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$222	$553	$289	$(842)	$222
OTHER COMPREHENSIVE INCOME					
Pensions and OPEB prior service costs	(2)	(1)	—	1	(2)
Amortized loss on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available for sale securities	11	—	12	(12)	11
Other comprehensive income (loss)	3	(1)	12	(11)	3
Income taxes (benefits) on other comprehensive income (loss)	1	(1)	5	(4)	1

Other comprehensive income, net of tax	2	—	7	(7)	2
COMPREHENSIVE INCOME	$224	$553	$296	$(849)	$224

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

For the Three Months Ended September 30, 2011	FES	FGCO	NGC	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,445	$686	$371	$(1,035)	$1,467
OPERATING EXPENSES:					
Fuel	6	323	57	—	386
Purchased power from affiliates	1,031	4	55	(1,035)	55
Purchased power from non-affiliates	330	(2)	—		