CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-K
February 16, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010
OR

o **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
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY	34-4375005

	(An Ohio Corporation) **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	
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**
1-446	**METROPOLITAN EDISON COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**23-0870160**
1-3522	**PENNSYLVANIA ELECTRIC COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**25-0718085**

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SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, $0.10 par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Registrant	Title of Each Class
Ohio Edison Company	Common Stock, no par value per share
The Cleveland Electric Illuminating Company	Common Stock, no par value per share
The Toledo Edison Company	Common Stock, $5.00 par value per share
Jersey Central Power & Light Company	Common Stock, $10.00 par value per share
Metropolitan Edison Company	Common Stock, no par value per share
Pennsylvania Electric Company	Common Stock, $20.00 par value per share
FirstEnergy Solutions Corp.	Common Stock, no par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o	FirstEnergy Corp.
Yes o No þ	FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ	FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company, FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o	FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company, FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o	FirstEnergy Corp.
Yes o No þ	

FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

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

Yes o No þ	FirstEnergy Corp.
Yes þ No o	FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company

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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 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, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric 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, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter.
FirstEnergy Corp., $10,712,157,232 as of June 30, 2010; and for all other registrants, none.
Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

CLASS	OUTSTANDING AS OF JANUARY 31, 2011
FirstEnergy Corp., $0.10 par value	304,835,407
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
The Cleveland Electric Illuminating Company, no par value	67,930,743
The Toledo Edison Company, $5 par value	29,402,054
Jersey Central Power & Light Company, $10 par value	13,628,447
Metropolitan Edison Company, no par value	741,880
Pennsylvania Electric Company, $20 par value	4,427,577

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company common stock.
Documents incorporated by reference (to the extent indicated herein):

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
Proxy Statement for 2011 Annual Meeting of Stockholders to be held May 17, 2011	Part III

This combined Form 10-K is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric 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.

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OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

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Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management s intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms anticipate, potential, expect, believe, estimate and similar words. Forward-lo 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 in the various states in which we do business.
- Business and regulatory impacts from ATSI s realignment into PJM Interconnection, L.L.C., economic or weather conditions affecting future sales and margins.
- Changes in markets for energy services.
- Changing energy and commodity market prices and availability.
- Financial derivative reforms that could increase our liquidity needs and collateral costs, replacement power costs being higher than anticipated or inadequately hedged.
- The continued ability of FirstEnergy s 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 and coal combustion residual regulations.
- The potential impacts of any laws, rules or regulations that ultimately replace CAIR.
- The uncertainty of the timing and amounts of the capital expenditures needed to resolve any NSR litigation or other potential similar regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).
- Adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC.
- Adverse legal decisions and outcomes related to Met-Ed s and Penelec s transmission service charge appeal at the Commonwealth Court of Pennsylvania.
- Any impact resulting from the receipt by Signal Peak of the Department of Labor s notice of a potential pattern of violations at Bull Mountain Mine No.1.
- The continuing availability of generating units and their ability to operate at or near full capacity.
- 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 (including employee workforce initiatives).
- The ability to improve electric commodity margins and the impact of, among other factors, the increased cost of coal and coal transportation on such margins and the ability to experience growth in the distribution business.
- The changing market conditions that could affect the value of assets held in the registrants nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The ability to access the public securities and other capital and credit markets in accordance with FirstEnergy s financing plan and the cost of such capital.
- Changes in general economic conditions affecting the registrants.
- The state of the capital and credit markets affecting the registrants.
- Interest rates and any actions taken by credit rating agencies that could negatively affect the registrants access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.

The continuing uncertainty of the national and regional economy and its impact on the registrants major industrial and commercial customers.

Issues concerning the soundness of financial institutions and counterparties with which the registrants do business.

The expected timing and likelihood of completion of the proposed merger with Allegheny, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management s time and attention from FirstEnergy s ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.

The risks and other factors discussed from time to time in the registrants SEC filings, and other similar factors.

Dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations. 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 the registrants 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 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:

ATSI	American Transmission Systems, Incorporated, owns and operates transmission facilities
Beaver Valley	Beaver Valley Power Station
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial and other corporate support services
FEV	FirstEnergy Ventures Corp., invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
Global Rail	A joint venture between FirstEnergy Ventures Corp. and WMB Loan Ventures II LLC, that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	Met-Ed, Penelec and Penn
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Perry	Perry Nuclear Power Plant
Shelf Registrants	FirstEnergy, OE, CEI, TE, JCP&L, Met-Ed and Penelec
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FirstEnergy Ventures Corp. and WMB Loan Ventures LLC, that owns mining and coal transportation operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec

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

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
Allegheny	Allegheny Energy, Inc. is the parent holding company of Allegheny Supply, Monongahela Power Company, The Potomac Edison Company and West Penn Power Company
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARO	Asset Retirement Obligation
AS	Allegheny Energy Supply Company, LLC owns and operates non-nuclear generating facilities and purchases and sells energy and energy-related commodities

BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule

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GLOSSARY OF TERMS, Cont d.

CATR	Clean Air Transport Rule
CBP	Competitive Bid Process
CO_2	Carbon dioxide
CRDM	Control Rod Drive Mechanism
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DCPD	Deferred Compensation Plan for Outside Directors
DPA	Department of the Public Advocate, Division of Rate Counsel (New Jersey)
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
FRR	Fixed Resource Requirement
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
IFRS	International Financial Reporting Standards
IRS	Internal Revenue Service
ISO	Independent System Operators
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-Emitting Diode
LOC	Letter of Credit
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MDPSC	Maryland Public Service Commission
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody s	Moody s Investors Service, Inc.
MRO	Market Rate Offer
MTEP	MISO Regional Transmission Expansion Plan
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review

NOAC	Northwest Ohio Aggregation Coalition
NOPEC	Northeast Ohio Public Energy Council
NOV	Notice of Violation
NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
NYPSC	New York Public Service Commission
NYSEG	New York State Electric and Gas Corporation
OCC	Ohio Consumers Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation

GLOSSARY OF TERMS, Cont d.

PCRB	Pollution Control Revenue Bond
PICA	Pennsylvania Intergovernmental Cooperation Authority
PJM	PJM Interconnection L. L. C.
POLR	Provider of Last Resort; an electric utility s obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSCWV	Public Service Commission of West Virginia
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
QSPE	Qualifying Special-Purpose Entity
RCP	Rate Certainty Plan
RECs	Renewable Energy Credits
RFP	Request for Proposal
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Service
SB221	Ohio Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRECs	Solar Renewable Energy Credits
TBC	Transition Bond Charge
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VERO	Voluntary Enhanced Retirement Option
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission

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Part IV

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PART I

ITEM 1. BUSINESS

Proposed Merger with Allegheny

As previously disclosed, on February 10, 2010, FirstEnergy entered into an Agreement and Plan of Merger, subsequently amended on June 4, 2010 (Merger Agreement), with Element Merger Sub, Inc., a Maryland corporation, its wholly-owned subsidiary (Merger Sub) and Allegheny a Maryland corporation. Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny with Allegheny continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny common stock, including grants of restricted common stock, would automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy, and Allegheny stockholders would own approximately 27% of the combined company. FirstEnergy would also assume all outstanding Allegheny debt.

Pursuant to the Merger Agreement, completion of the merger is conditioned upon, among other things, shareholder approval of both companies, which was received on September 14, 2010; the SEC s clearance of a registration statement registering the FirstEnergy common stock to be issued in connection with the merger, which occurred on July 16, 2010. Approval of the merger was received from the VSCC on September 9, 2010. Approval from the FERC and from the PSCWV was received on December 16, 2010. Approval from the MDPSC was received on January 18, 2011. On January 7, 2011, we were notified by the DOJ that it had completed its review of the merger and closed its investigation. The proposed merger is also conditioned upon receipt of the approval of the PPUC. The Merger Agreement also contains certain termination rights for both FirstEnergy and Allegheny, and further provides for the payment of fees and expenses upon termination under specified circumstances.

FirstEnergy and Allegheny currently anticipate completing the merger in the first quarter of 2011. Although FirstEnergy and Allegheny believe that they will receive the required authorizations, approvals and consents to complete the merger, there can be no assurance as to the timing of these authorizations, approvals and consents or as to FirstEnergy s and Allegheny s ultimate ability to obtain such authorizations, consents or approvals (or any additional authorizations, approvals or consents which may otherwise become necessary) or that such authorizations, approvals or consents will be obtained on terms and subject to conditions satisfactory to Allegheny and FirstEnergy. Further information concerning the proposed merger is included in the Registration Statement filed by FirstEnergy with the SEC in connection with the merger.

The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy s principal business is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries: OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed and Penelec; and of its generating and marketing subsidiary, FES. FirstEnergy s consolidated revenues are primarily derived from electric service provided by its utility operating subsidiaries and the revenues of its other principal subsidiary, FES. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., FirstEnergy Facilities Services Group, LLC, FirstEnergy Fiber Holdings Corp., GPU Power, Inc., GPU Nuclear, Inc., MARBEL Energy Corporation and FESC.

FES was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to wholesale and retail customers. FES also owns and operates, through its subsidiary, FGCO, FirstEnergy s fossil and hydroelectric generating facilities and owns, through its subsidiary, NGC, FirstEnergy s nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, organized under the laws of the State of Ohio in 1998, operates and maintains NGC s nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FGCO and NGC, as well as the output relating to leasehold interests of the Ohio Companies in certain of those facilities that are subject to sale and leaseback arrangements with non-affiliates, pursuant to full output, cost-of-service PSAs.

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FirstEnergy s generating portfolio includes 13,436 MW of diversified capacity (FES 13,236 MW and JCP&L 200 MW). Within FES portfolio, approximately 7,157 MW, or 54.1%, consist of coal-fired capacity; 3,991 MW, or 30.2%, consist of nuclear capacity; 1,151 MW, or 8.7%, consist of oil and natural gas peaking units; 451 MW, or 3.4%, consist of hydroelectric capacity, 376 MW, or 2.8%, are from wind facilities; and 110 MW, or 0.8%, consist of capacity from FGCO s current 4.85% entitlement to the generation output owned by the OVEC. FirstEnergy s nuclear and non-nuclear facilities are operated by FENOC and FGCO, respectively, and, except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates referred to above for which the corresponding output is available to FES through power sale agreements, are all owned directly by NGC and FGCO, respectively. The FES generating assets are concentrated primarily in Ohio and Pennsylvania. All FES units are currently dedicated to MISO except Beaver Valley and Seneca Pumped Storage Plant, which are designated as a PJM resource. Additionally, see FERC Matters for RTO Realignment.

FES, FGCO and NGC comply with the regulations, orders, policies and practices prescribed by the SEC and the FERC. In addition, NGC and FENOC comply with the regulations, orders, policies and practices prescribed by the NRC.

The Utilities combined service areas encompass approximately 36,100 square miles in Ohio, New Jersey and Pennsylvania. The areas they serve have a combined population of approximately 11.3 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio. The area it serves has a population of approximately 2.8 million. OE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

OE owns all of Penn s outstanding common stock. Penn was organized under the laws of the Commonwealth of Pennsylvania in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business in the State of Ohio (see Item 2 Properties). Penn furnishes electric service to communities in 1,100 square miles of western Pennsylvania. The area it serves has a population of approximately 0.4 million. Penn complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of approximately 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.8 million. CEI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of approximately 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.8 million. TE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns transmission assets that were formerly owned by the Ohio Companies and Penn. ATSI owns major, high-voltage transmission facilities, which consist of approximately 5,821 pole miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV. Effective October 1, 2003, ATSI transferred operational control of its transmission facilities to MISO. On December 17, 2009, the FERC authorized ATSI to transfer operational control of its facilities to PJM. As described below in FERC Matters the transfer is scheduled to occur on June 1, 2011. ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and applicable regulatory requirements to ensure reliable service to customers. Additionally, see FERC Matters for RTO Realignment. ATSI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and applicable state regulatory authorities.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.6 million. JCP&L complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and the NJBPU.

Met-Ed was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. Met-Ed provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately

1.3 million. Met-Ed complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PPUC.

Penelec was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. Penelec provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.6 million. Penelec, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in Waverly, New York and its vicinity. Penelec complies with the regulations, orders, policies and practices prescribed by the SEC, FERC, NYPSC and PPUC, as applicable.

FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies.
Reference is made to Note 15, Segment Information, of the Notes to Consolidated Financial Statements contained in Item 8 for information regarding FirstEnergy s reportable segments.

Utility Regulation

State Regulation

Each of the Utilities retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the state in which each company operates in Ohio by the PUCO, in New Jersey by the NJBPU and in Pennsylvania by the PPUC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As a competitive retail electric supplier serving retail customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan, and Illinois, FES is subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES and its public utility affiliates. In addition, if FES or any of its subsidiaries were to engage in the construction of significant new generation facilities, they would also be subject to state siting authority.

Federal Regulation

With respect to their wholesale and interstate electric operations and rates, the Utilities, ATSI, FES, FGCO and NGC are subject to regulation by the FERC. Under the FPA, the FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require ATSI, Met-Ed, JCP&L and Penelec to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission service over ATSI s facilities is provided by MISO under its open access transmission tariff although as explained herein effective June 1, 2011 transmission service over ATSI s facilities will be provided pursuant to PJM s open access transmission tariff. Transmission service over Met-Ed s, JCP&L s and Penelec s facilities is provided by PJM under its open access transmission tariff. The FERC also regulates unbundled transmission service to retail customers. Additionally, see FERC Matters for RTO Realignment.

The FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon a showing that the seller cannot exert market power in generation or transmission. FES, FGCO and NGC have been authorized by the FERC to sell wholesale power in interstate commerce and have a market-based tariff on file with the FERC. By virtue of this tariff and authority to sell wholesale power, each company is regulated as a public utility under the FPA. However, consistent with its historical practice, the FERC has granted FES, FGCO and NGC a waiver from most of the reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, the FERC also granted FES, FGCO and NGC blanket authority to issue securities and assume liabilities under Section 204 of the FPA. As a condition to selling electricity on a wholesale basis at market-based rates, FES, FGCO and NGC, like all other entities granted market-based rate authority, must file electronic quarterly reports with the FERC, listing their sales transactions for the prior quarter.

The nuclear generating facilities owned and leased by NGC are subject to extensive regulation by the NRC. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the licenses. FENOC is the licensee for the operating nuclear plants and has direct compliance responsibility for NRC matters. FES controls the economic dispatch of NGC s plants. See Nuclear Regulation below.

Regulatory Accounting

The Utilities and ATSI recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Utilities respective transition and regulatory plans. Based on those plans, the Utilities and ATSI continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Utilities and ATSI continue the application of regulatory accounting to those operations.

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to its operating utilities since their rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense (regulatory assets) if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with GAAP.

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry restructuring contain similar provisions that are reflected in the Utilities respective state regulatory plans. These provisions include:

- restructuring the electric generation business and allowing the Utilities customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the POLR obligations to customers in the Utilities service areas;
- providing the Utilities with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Utilities transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Reliability Initiatives

In 2005, Congress amended the FPA to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, FGCO, FENOC and ATSI. The NERC, as the ERO, is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

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 Reliability*First*. Moreover, it is clear that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the FPA provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, 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.

In April 2007, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system within the PJM region and found it to be in full compliance with all audited reliability standards. In May 2010, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system in the Midwest ISO region and, subject to certain nonmaterial items, found it to be in compliance with the audited reliability standards. FirstEnergy s PJM facilities are next due for the periodic audit by Reliability*First* in 2011.

Ohio Regulatory Matters

The Ohio Companies operate under an ESP, which expires on May 31, 2011, that provides for generation supplied through a CBP. The ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the May 2009 CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million). Applications for rehearing of the PUCO order in the distribution case were filed by the Ohio Companies and one other party. The Ohio Companies raised numerous issues in their application for rehearing related to rate recovery of certain expenses, recovery of line extension costs, the level of rate of return and the amount of general plant balances. On February 2, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing filed both by the Ohio Companies and by the other party.

On March 23, 2010, the Ohio Companies filed an application for a new ESP. The new ESP will go into effect on June 1, 2011 and conclude on May 31, 2014. The PUCO approved the new ESP on August 25, 2010 with certain modifications. The material terms of the new ESP include: a CBP similar to the one used in May 2009 and the one proposed in the October 2009 MRO filing; a 6% generation discount to certain low-income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (initial auctions scheduled for October 20, 2010 and January 25, 2011); no increase in base distribution rates through May 31, 2014; a load cap of no less than 80%, which also applies to any tranches assigned post auction; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. Rider DCR substitutes for Rider DSI which terminates under the current ESP. The Ohio Companies also agreed not to pay certain costs related to the companies 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, established a $12 million fund to assist low income customers over the term of the ESP, and agreed to additional energy efficiency benefits. Many of the existing riders approved in the previous ESP remain in effect, some with modifications. The new ESP resolved proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and the integration into PJM. FirstEnergy recorded approximately $39.5 million of regulatory asset impairments and expenses related to the ESP. On September 24, 2010, an application for rehearing was filed by the OCC and two other parties. On February 9, 2011, the PUCO issued an Entry on Rehearing denying the applications for rehearing.

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent to approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required through 2025. Utilities are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018.

On December 15, 2009, the Ohio Companies filed the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The Ohio Companies three year portfolio plan is still awaiting decision from the PUCO, which is delaying the launch of the programs described in the plan. As a result, the Ohio Companies filed on January 11, 2011, a request for amendment of OE s 2010 energy efficiency and peak demand reduction benchmarks to levels actually achieved in 2010. Because the Commission indicated that it would revise all of the Ohio Companies 2010, 2011, and 2012 benchmarks when addressing the Ohio Companies three year portfolio plan, and an order has yet to be issued on that plan, CEI and TE also requested a waiver of their respective yet-to-be defined 2010 energy efficiency benchmarks if and only to the degree one is deemed necessary to bring these companies into compliance with their 2010 energy efficiency obligations. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a penalty.

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Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they served in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs were used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On March 10, 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Ohio Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark, which application is still pending. In July 2010, the Ohio Companies initiated an additional RFP to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2010 and 2011. As a result of this RFP, contracts were executed in August 2010. On January 11, 2011, the Ohio Companies filed an application with the PUCO seeking an amendment to each of their 2010 alternative energy requirements for solar RECs generated in Ohio due to the insufficient quantity of solar energy resources reasonably available in the market. The PUCO has not yet ruled on that application.

On February 12, 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. On March 3, 2010, the PUCO ordered that rates for the affected customers be set at a level that will provide bill impacts commensurate with charges in place on December 31, 2008 and authorized the Ohio Companies to defer incurred costs equivalent to the difference between what the affected customers would have paid under previously existing rates and what they pay with the new credit in place. Tariffs implementing this new credit went into effect on March 17, 2010. On April 15, 2010, the PUCO issued a Second Entry on Rehearing that expanded the group of customers to which the new credit would apply and authorized deferral for the associated additional amounts. The PUCO also stated that it expected that the new credit would remain in place through at least the 2011 winter season, and charged its staff to work with parties to seek a long term solution to the issue. Tariffs implementing this newly expanded credit went into effect on May 21, 2010, and the proceeding remains open. The hearing in the matter is set to commence on February 16, 2011.

Pennsylvania Regulatory Matters

The PPUC adopted a Motion on January 28, 2010 and subsequently entered an Order on March 3, 2010 which denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructed Met-Ed and Penelec to work with the various intervening parties to file a recommendation to the PPUC regarding the establishment of a separate account for all marginal transmission losses collected from ratepayers plus interest to be used to mitigate future generation rate increases beginning January 1, 2011. On March 18, 2010, Met-Ed and Penelec filed a Petition with the PPUC requesting that it stay the portion of the March 3, 2010 Order requiring the filing of tariff supplements to end collection of costs for marginal transmission losses. By Order entered March 25, 2010, the PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed the plan to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and the plan for the use of these funds to mitigate future generation rate increases commencing January 1, 2011. The PPUC approved this plan on June 7, 2010. On April 1, 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. Although the ultimate outcome of this matter cannot be determined at this time, Met-Ed and Penelec believe that they should prevail in the appeal and therefore expect to fully recover the approximately $252.7 million ($188.0 million for Met-Ed and $64.7 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011. The argument before the Commonwealth Court, *en banc*, was held on December 8, 2010.

On May 20, 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the period June 1, 2010 through December 31, 2010, including marginal transmission losses as approved by the PPUC, although the

recovery of marginal losses will be subject to the outcome of the proceeding related to the 2008 TSC filing as described above. The TSC for Met-Ed s customers was increased to provide for full recovery by December 31, 2010.
Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service through a prudent mix of long-term, short-term and spot market generation supply with a staggered procurement schedule that varies by customer class, using a descending clock auction. On August 12, 2009, the parties to the proceeding filed a settlement agreement of all but two issues, and the PPUC entered an Order approving the settlement and the generation procurement plan on November 6, 2009. Generation procurement began in January 2010.
On February 8, 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. On July 29, 2010, the parties to the proceeding filed a Joint Petition for Settlement of all issues. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn s June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Met-Ed, Penelec and Penn jointly filed a SMIP with the PPUC on August 14, 2009. This plan proposed a 24-month assessment period in which the Pennsylvania Companies will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs of approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the SMIP as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; denying the recovery of interest through the automatic adjustment clause; providing for the recovery of reasonable and prudent costs net of resulting savings from installation and use of smart meters; and requiring that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the SMIP for the Pennsylvania Companies. The PPUC entered its Order on June 9, 2010, consistent with the Chairman s Motion. On June 24, 2010, Met-Ed, Penelec and Penn filed a Petition for Reconsideration of a single portion of the PPUC s Order regarding the future ability to include smart meter costs in base rates. On August 5, 2010, the PPUC granted in part the petition for reconsideration by deleting language from its original order that would have precluded Met-Ed, Penelec and Penn from seeking to include smart meter costs in base rates at a later time. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement, which addressed how Met-Ed and Penelec were going to implement direct access to a competitive market for the generation of electricity, allows Met-Ed and Penelec to apply over-collection of NUG costs for select and isolated months to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists. In response to the Tentative Order, various parties filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

New Jersey Regulatory Matters

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2010, the accumulated deferred cost balance was a credit of approximately $37 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. On February 10, 2011, the NJBPU approved a stipulation which allows the change in rates to become effective March 1, 2011.

On March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009 estimated at $736 million (in 2003 dollars). This matter is currently pending before the NJBPU.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The NJBPU adopted an order establishing the general process and contents of specific EMP plans that must be filed by New Jersey electric and gas utilities in order to achieve the goals of the EMP. On April 16, 2010, the NJBPU issued an order indefinitely suspending the requirement of New Jersey utilities to submit Utility Master Plans until such time as the status of the EMP has been made clear. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

FERC Matters

Rates for Transmission Service Between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC s intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as SECA) during a 16-month transition period. In 2005, the FERC set the SECA for hearing. The presiding ALJ issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM and the transmission owners, and directing new compliance filings. This decision was subject to review and approval by the FERC. On May 21, 2010, FERC issued an order denying pending rehearing requests and an Order on Initial Decision which reversed the presiding ALJ s rulings in many respects. Most notably, these orders affirmed the right of transmission owners to collect SECA charges with adjustments that modestly reduce the level of such charges, and changes to the entities deemed responsible for payment of the SECA charges. The Ohio Companies were identified as load serving entities responsible for payment of additional SECA charges for a portion of the SECA period (Green Mountain/Quest issue). FirstEnergy executed settlements with AEP, Dayton and the Exelon parties to fix FirstEnergy s liability for SECA charges originally billed to Green Mountain and Quest for load that returned to regulated service during the SECA period. The AEP, Dayton and Exelon, settlements were approved by FERC on November 23, 2010, and the relevant payments made. Rehearings remain pending in this proceeding.

PJM Transmission Rate

On April 19, 2007, FERC issued an order (Opinion 494) finding that the PJM transmission owners existing license plate or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, FERC directed 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. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a load flow methodology (DFAX), which is generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities.

The FERC s Opinion 494 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision on August 6, 2009. The court affirmed FERC s ratemaking treatment for existing transmission facilities, but found that FERC had not supported its decision to allocate costs for new 500+ kV facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

In an order dated January 21, 2010, FERC set the matter for paper hearings meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments and then reply comments on later dates. PJM filed certain studies with FERC on April 13, 2010, in response to the FERC order. PJM s filing demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain eastern utilities in PJM bearing the majority of their costs. 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 commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. FERC is expected to act by May 31, 2011.

RTO Realignment

On December 17, 2009, FERC issued an order approving, subject to certain future compliance filings, ATSI s withdrawal from MISO and integration into PJM. This move, which is expected to be effective on June 1, 2011, allows FirstEnergy to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy s transmission assets and operations are divided between PJM and MISO. The realignment will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. In the order, FERC approved FirstEnergy s proposal to use a FRR Plan to obtain capacity to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years.

FirstEnergy successfully conducted the FRR auctions on March 19, 2010. Moreover, the ATSI zone loads participated in the PJM base residual auction for the 2013 delivery year. Successful completion of these steps secured the capacity necessary for the ATSI footprint to meet PJM s capacity requirements. On August 25, 2010, the PUCO issued an order in the 2010 ESP Case approving a settlement that, among other things, called for the PUCO to withdraw its opposition to the RTO consolidation. In addition, the order approved a wholesale procurement process, and certain retail choice policies, that reflected ATSI s entry into PJM on June 1, 2011.

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On February 1, 2011, ATSI in conjunction with PJM filed its proposal with FERC for moving its transmission rate into PJM s tariffs. FirstEnergy expects ATSI to enter PJM on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. Additional FERC proceedings are either pending or expected in which the amount of exit fees, transmission cost allocations, and costs associated with long term firm transmission rights payable by the ATSI zone upon its withdrawal from the Midwest ISO will be determined. In addition, certain parties may protest other aspects of ATSI s integration into PJM, and certain of these matters remain outstanding and will be resolved in future FERC proceedings. The outcome of these proceedings cannot be predicted.

MISO Multi-Value Project Rule Proposal

On July 15, 2010, MISO and certain MISO transmission owners jointly filed with FERC their proposed cost allocation methodology for certain new transmission projects. The new transmission projects described as MVPs are a class of MTEP projects. The filing parties proposed to allocate the costs of MVPs by means of a usage-based charge that will be applied to all loads within the MISO footprint, and to energy transactions that call for power to be wheeled through the MISO as well as to energy transactions that source in the MISO but sink outside of MISO. The filing parties expect that the MVP proposal will fund the costs of large transmission projects designed to bring wind generation from the upper Midwest to load centers in the east. The filing parties requested an effective date for the proposal of July 16, 2011. On August 19, 2010, MISO s Board approved the first MVP project the Michigan Thumb Project. Under MISO s proposal, the costs of MVP projects approved by MISO s Board prior to the anticipated June 1, 2011 effective date of FirstEnergy s integration into PJM would continue to be allocated to FirstEnergy. MISO estimated that approximately $11 million in annual revenue requirements would be allocated to the ATSI zone associated with the Michigan Thumb Project upon its completion.

On September 10, 2010, FirstEnergy filed a protest to the MVP proposal arguing that MISO s proposal to allocate costs of MVP projects across the entire MISO footprint does not align with the established rule that cost allocation is to be based on cost causation (the beneficiary pays approach). FirstEnergy also argued that, in light of progress to date in the ATSI integration into PJM, it would be unjust and unreasonable to allocate any MVP costs to the ATSI zone, or to ATSI. Numerous other parties filed pleadings on MISO s MVP proposal.

On December 16, 2010, FERC issued an order approving the MVP proposal without significant change. FERC s order was not clear, however, as to whether the MVP costs would be payable by ATSI or load in the ATSI zone. FERC stated that the MISO s tariffs obligate ATSI to pay all charges that attach prior to ATSI s exit but ruled that the question of the amount of costs that are to be allocated to ATSI or to load in the ATSI zone were beyond the scope of FERC s order and would be addressed in future proceedings.

On January 18, 2011, FirstEnergy filed for rehearing of FERC s order. In its rehearing request, the Company argued that because the MVP rate is usage-based, costs could not be applied to ATSI, which is a stand-alone transmission company that does not use the transmission system. FirstEnergy also renewed its arguments regarding cost causation and the impropriety of allocating costs to the ATSI zone or to ATSI. FirstEnergy cannot predict the outcome of these proceedings at this time.

Sales to Affiliates

FES has received authorization from FERC to make wholesale power sales to the Utilities. FES actively participates in auctions conducted by or on behalf of the Utilities to obtain the power and related services necessary to meet the Utilities POLR obligations. Because of the merger with FirstEnergy, AS is considered an affiliate of the Utilities for purposes of FERC s affiliate restriction regulations. This requires AS to obtain prior FERC authorization to make sales to the Utilities when it successfully participates in the Utilities POLR auctions.

FES currently supplies the Ohio Companies with a portion of their capacity, energy, ancillary services and transmission under a Master SSO Supply Agreement for a two-year period ending May 31, 2011. FES won 51 tranches in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International on May 13-14, 2009. Other winning suppliers have assigned their Master SSO Supply Agreements to FES, five of which were effective in June, two more in July, four more in August and ten more in September, 2009. FES also supplies power used by Constellation to serve an additional five tranches. As a result of these arrangements, FES serves 77 tranches, or 77% of the POLR load of the Ohio Companies until May 31, 2011.

On October 20, 2010, FES participated in a descending clock auction for POLR service administered by the Ohio Companies and their consultant, CRA International, for the following periods: June 1, 2011 through May 31, 2012; June 1, 2011, through May 31, 2013; and June 1, 2010 through May 31, 2014. The Ohio Companies offered 17, 17, and 16 tranches for these periods, respectively. FES won 10, 7, and 3 tranches, respectively, for these periods. On January 25, 2011, the Ohio Companies conducted a second auction offering the same product for identical time periods. FES won 3, 0, and 3 tranches, respectively, for these periods. FES entered into a Master SSO Supply Agreement to provide capacity, energy, ancillary services, and congestion costs to the Ohio Companies for the tranches won. Under the ESP in effect for these time periods, the Ohio Companies are responsible for payment of noncontrollable transmission costs billed by PJM for POLR service.

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On October 18, 2010, FES participated in a descending clock auction for POLR service administered by both Met-Ed and Penelec and their consultant, National Economic Research Associates (NERA) for the following tranche products and delivery periods: Residential 5-month, Residential 24-month, Commercial 5-month, Commercial 12-month and Industrial 12-month. All 5-month delivery periods are from January 1, 2011 through May 31, 2011, all 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 7 Residential 5-month tranches, 4 Residential 24-month tranches, 6 Commercial 5-month tranches, 6 Commercial 12-month tranches and 1 Industrial tranche while Penelec offered 5 Residential 5-month tranches, 3 Residential 24-month tranches, 5 Commercial 5-month tranches, 5 Commercial 12-month tranches and 1 Industrial tranche.

For Met-Ed offerings, FES won 4 Residential 5-month tranches, 2 Residential 24-month tranches, 1 Commercial 5-month tranche, 1 Commercial 12-month tranche and zero Industrial tranches. For Penelec offerings, FES won 1 Residential 5-month tranche, 1 Residential 24-month tranche, zero Commercial 5-month tranches, zero Commercial 12-month tranches and zero Industrial tranches. FES entered into separate Supplier Master Agreements (SMA) to provide capacity, energy, ancillary services, and congestion costs with Met-Ed and Penelec for each product won. Under the terms and conditions of the SMA, Met-Ed and Penelec are responsible for payment of noncontrollable transmission costs billed by PJM.

On January 18 to 20, 2011 FES participated in a descending clock auction for POLR service administered by Met-Ed, Penelec, and Penn Power and their consultant, NERA for the following tranche products and delivery periods: Residential 12-month, Residential 24-month, Commercial 12-month and Industrial 12-month. All 12-month delivery periods are from June 1, 2011 through May 31, 2012 while all 24-month delivery periods are from June 1, 2011 through May 31, 2013. Met-Ed offered 3 Residential 12-month tranches, 4 Residential 24-month tranches, 6 Commercial 12-month tranches and 11 Industrial tranches. Penelec offered 3 Residential 12-month tranches, 2 Residential 24-month tranches, 5 Commercial 12-month tranches and 11 Industrial tranches. Penn Power offered 2 Residential 12-month tranches, 1 Residential 24-month tranche, 3 Commercial 12-month tranches and 3 Industrial tranches.

For Met-Ed offerings, FES won 1 Commercial 12-month tranche and zero for the remaining products. For Penelec and Penn Power offerings, FES won no tranches. FES entered into a SMA to provide capacity, energy, ancillary services, and congestion costs with Met-Ed for the product won. Under the terms and conditions of the SMA, Met-Ed is responsible for payment of noncontrollable transmission costs billed by PJM.

Capital Requirements

Our capital spending for 2011 is expected to be approximately $1.4 billion (excluding nuclear fuel). For 2012 and 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion that excludes currently unplanned investment opportunities or future mandated spending. Baseline capital initiatives promote reliability, improve operations, and support current environmental and energy efficiency directives. Our capital investments for additional nuclear fuel are expected to be $133 million, $300 million and $183 million in 2011, 2012 and 2013, respectively.

Anticipated capital expenditures for the Utilities, FES and FirstEnergy s other subsidiaries for 2011, excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the betterment of existing facilities and for the completion of generating capacity, construction, transmission lines, distribution lines, substations and other assets.

	2010 Actual[(1)]	**Capital Expenditures Forecast 2011**
	(In millions)	
OE	$ 138	$ 127
Penn	26	20
CEI	113	117
TE	46	37
JCP&L	190	181

Met-Ed	106	89
Penelec	135	121
ATSI	67	60
FGCO	581	215
NGC	333	393
Other subsidiaries	78	60
Total	$ 1,813	$ 1,420

(1) Excludes nuclear fuel.

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During the 2011-2015 period, maturities of, and sinking fund requirements for, long-term debt of FirstEnergy and its subsidiaries are:

	Long-Term Debt Redemption Schedule		
	2011	2012-2015	Total
		(In millions)	
FirstEnergy	$ 250	$	$ 250
FES	163	692	855
OE		150	150
Penn	1	4	5
CEI	20	396	416
JCP&L	32	149	181
Met-Ed		400	400
Penelec		150	150
Other[(1)]	(21)	229	208
Total	$ 445	$ 2,170	$ 2,615

(1) Includes elimination of certain intercompany debt.

The following tables display consolidated operating lease commitments as of December 31, 2010.

Operating Leases	Lease Payments	Capital Trust	Net
		(In millions)	
2011	$ 329	$ 116	$ 213
2012	365	125	240
2013	367	130	237
2014	363	131	232
2015	365	91	274
Years thereafter	2,150	32	2,118
Total minimum lease payments	$ 3,939	$ 625	$ 3,314

Operating Leases	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
2011	$ 192	$ 146	$ 4	$ 64	$ 6	$ 4	$ 3
2012	230	147	3	64	5	4	3
2013	236	147	3	64	5	4	3
2014	234	146	3	64	5	4	2
2015	238	146	3	64	4	4	2
Years thereafter	1,895	166	6	79	48	40	23
Total minimum lease payments	$ 3,025	$ 898	$ 22	$ 399	$ 73	$ 60	$ 36

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2011, FirstEnergy expects to satisfy these requirements with internal cash from operations external funds may also be raised in the capital markets as market conditions warrant. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

FirstEnergy had approximately $700 million of short-term indebtedness as of December 31, 2010, comprised of borrowings under the $2.75 billion revolving line of credit described below. Total short-term bank lines of committed credit to FirstEnergy, FES and the Utilities as of January 31, 2011 were approximately $3.2 billion.

FirstEnergy, along with certain of its subsidiaries, are party to a $2.75 billion five-year revolving credit facility. FirstEnergy has the ability to request an increase in the total commitments available under this facility up to a maximum of $3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. The annual facility fee is 0.125%.

As of January 31, 2011, FES had a $100 million term loan in addition to a $1 billion credit limit associated with FirstEnergy s $2.75 billion revolving credit facility. Also, an aggregate of $395 million of accounts receivable financing facilities through the Ohio and Pennsylvania Companies may be accessed to meet working capital requirements and for other general corporate purposes. FirstEnergy s available liquidity as of January 31, 2011, is described in the following table.

Company	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[1]	Revolving	Aug. 2012	$ 2,750	$ 2,245
FES	Term loan	Mar. 2011	100	
Ohio and Pennsylvania Companies	Receivables financing	Various[2]	395	237
		Subtotal	$ 3,245	$ 2,482
		Cash		668
		Total	$ 3,245	$ 3,150

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) Ohio $250 million matures March 30, 2011; Pennsylvania $145 million matures June 17, 2011 with optional extension terms.

FirstEnergy s primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2010, the holding company received $850 million of cash dividends on common stock from its subsidiaries and paid $670 million in cash dividends to common shareholders.

As of December 31, 2010, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.4 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $124 million and $26 million, respectively, as of December 31, 2010. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $394 million and $343 million, respectively, under provisions of their senior note indentures as of December 31, 2010.

Based upon FGCO s FMB indenture, net earnings and available bondable property additions as of December 31, 2010, FGCO had the capability to issue $1.7 billion of additional FMBs under the terms of that indenture. Based upon NGC s FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $695 million of additional FMBs as of December 31, 2010.

To the extent that coverage requirements or market conditions restrict the subsidiaries abilities to issue desired amounts of FMBs or preferred stock, they may seek other methods of financing. Such financings could include the sale of preferred and/or preference stock or of such other types of securities as might be authorized by applicable regulatory authorities which would not otherwise be sold and could result in annual interest charges and/or dividend requirements in excess of those that would otherwise be incurred.

On September 22, 2008, the Shelf Registrants filed an automatically effective shelf registration statement with the SEC for an unspecified number and amount of securities to be offered thereon. The shelf registration provides FirstEnergy the flexibility to issue and sell various types of securities, including common stock, preferred stock, debt securities, warrants, share purchase contracts, and share purchase units. The Shelf Registrants may utilize the shelf registration statement to offer and sell unsecured, and in some cases, secured debt securities.

Nuclear Operating Licenses

On August 27, 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse Nuclear Power Station operating license for an additional twenty years, until 2037. On December 27 and 28, 2010, a group of petitioners filed a request for hearing, contending that FENOC failed to adequately consider wind or solar generation, or some combination thereof, as an alternative to license extension at Davis Besse. They further argued FENOC had failed to adequately assess the cost of a severe accident at Davis Besse. FENOC and the NRC staff responded to this pleading on January 21, 2011, demonstrating that none of the petitioners arguments were admissible contentions under the National Environmental Policy Act or NRC regulations. An Atomic Safety and Licensing Board panel is expected to determine whether a hearing is necessary in this matter.

The following table summarizes the current operating license expiration dates for FES nuclear facilities in service.

Station	In-Service Date	Current License Expiration
Beaver Valley Unit 1	1976	2036
Beaver Valley Unit 2	1987	2047
Perry	1986	2026
Davis-Besse	1977	2017

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2010, 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. FirstEnergy provides an additional $15 million parental guarantee associated with the funding of decommissioning costs for these units. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy s nuclear decommissioning trusts 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 its effects on particular businesses and the economy could also affect the values of the nuclear decommissioning trusts. The NRC recently issued guidance anticipating an increase in low-level radioactive waste disposal costs associated with the decommissioning of FirstEnergy s nuclear facilities. As a result, FirstEnergy s decommissioning funding obligations are expected to increase. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $118 million (but not more than $18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy s maximum potential assessment under these provisions would be $470 million (OE-$40 million, NGC-$408 million, and TE-$22 million) per incident but not more than $70 million (OE-$6 million, NGC-$61 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy s subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $1.4 billion (OE-$120 million, NGC-$1.22 billion, TE-$64 million) for replacement power costs incurred during an outage after an initial 26-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy s present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $9 million (OE-$1 million, NGC-$8 million, and TE-less than $1 million).

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FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $61 million (OE-$5 million, NGC-$52 million, TE-$2 million, Met Ed, Penelec, and JCP&L-less than $1 million each) during a policy year.

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy s plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy s insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.1 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

Hydro Relicensing

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. Authorization to operate the project is by a license issued by the FERC. The existing license expires on February 28, 2013.

In February 2011 FirstEnergy and PSEG filed a joint application with FERC to renew the license for an additional fifty years. The companies are pursuing relicensure through FERC s Integrated License Application Process (ILP). Under the ILP process FERC will assess the license applications, issue draft and final Environmental Assessments/Environmental Impact Studies (as required by NEPA), and provide opportunity for intervention and protests by affected third parties. FERC may hold hearings during the 2-year ILP licensure period. FirstEnergy expects FERC to issue the new license within the remaining portion of the 2-year ILP period. 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 (Kinzua) Pumped Storage Project is a 451 MW hydroelectric project located in Warren County, Pennsylvania. FGCO owns and operates the project. The current FERC license was issued on December 1, 1965, and will expire on November 30, 2015. FGCO expects to file its new license application on or before November 30, 2013. On November 23, 2010, FGCO filed its notice of intent to relicense and pre-application document (PAD). On November 30, 2010, the Seneca Nation of Indians (Salamanca, NY) filed a competing notice of intent to file a new license application and PAD. On January 28, 2011, FERC issued a notice of the competing notices of intent and PADs; commencement of prefiling process and scoping; request for comments on the PADs; and identification of issues and associated study requests.

FERC s ILP provides a 5 year period for preparation, submission and adjudication of the licenses. The first part is a 3-year period during which each of FirstEnergy and the Seneca Nation are to collect the information and conduct the studies necessary to support license applications. The second part is the same as the licensing process described above for Yards Creek.

Section 15 of the Federal Power Act provides that when there are competing license applications, insignificant differences between competing applications are not determinative and shall not result in transfer of the license for the project. Based on the facts and the law, FirstEnergy believes it qualifies for this incumbent preference . The timetable for a FERC decision cannot be predicted at this time.

Environmental Matters

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

Clean Air Act 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) under the CAA by burning lower-sulfur fuel, combustion controls and post-combustion controls, generating more electricity from lower-emitting plants and/or using emission allowances. Violations can result in the shutdown of the generating unit involved and/or civil or criminal penalties.

The Sammis, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NOx and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement.

In July 2008, three complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a safe, responsible, prudent and proper manner , one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint seeking certification as a class action with the eight named plaintiffs as the class representatives. FGCO believes the claims are without merit and intends to defend itself against the allegations made in those three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against GenOn Energy, Inc. (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999) and Met-Ed. 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. In September 2009, the Court granted Met-Ed s motion to dismiss New Jersey s and Connecticut s claims for injunctive relief against Met-Ed, but denied Met-Ed s motion to dismiss the claims for civil penalties. The parties dispute the scope of Met-Ed s indemnity obligation to and from Sithe Energy.

In January 2009, the EPA issued a NOV to GenOn alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. alleging that modifications at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR permitting in violation of the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station containing in all material respects identical allegations as the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification that was required 60 days prior to filing a citizen suit under the CAA. In January, 2011, the DOJ filed a complaint against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on alleged modifications at the Homer City Power Station 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 the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the State of New York intervened and have filed a separate complaint regarding the Homer City Station. Mission Energy Westside, Inc. is seeking indemnification from Penelec, the co-owner and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec s indemnity obligation to and from Mission Energy Westside, Inc. is under dispute and Penelec is unable to predict the outcome of this matter.

In January 2011, a complaint was filed against Penelec in the U.S. District Court for the Western District of Pennsylvania seeking damages based on the Homer City Station s air emissions. The complaint was also filed against the former co-owner, NYSEG and various current owners of the Homer City Station, including EME Homer City Generation L.P. and affiliated companies, including Edison International. The complaint also seeks certification as a class action and to enjoin the Homer City Station from operating except in a safe, responsible, prudent and proper manner. Penelec believes the claims are without merit and intends to defend itself against the allegations made in the complaint.

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 generating plants. The EPA s NOV alleges equipment replacements occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. FGCO received a request for certain operating and maintenance information and planning information for these same generating plants and notification that the EPA is evaluating whether certain maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO also received another information request regarding emission projections for the Eastlake generating plant. FGCO intends to comply with the CAA, including the EPA s information requests, but, at this time, is unable to predict the outcome of this matter.

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 vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. In December 2008, the Court reconsidered its prior ruling and 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 opinion. The Court ruled in a different case that a cap-and-trade program similar to CAIR, called the NOx SIP Call, cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the 8-hour ozone NAAQS. In July 2010, the EPA proposed the CATR to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management continues to assess the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. In August 2010, for example, management decided to idle certain units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NOx emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups, vacated the CAMR, ruling that the EPA failed to take the necessary steps to de-list coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. On January 20, 2011, the U.S. District Court for the District of Columbia denied a motion by the EPA for an extension of the deadline to issue final rules, ordering the EPA to issue such rules by February 21, 2011. The EPA also entered into a consent decree requiring it to propose MACT regulations for mercury and other hazardous air pollutants from electric generating units by March 16, 2011, and to finalize the regulations by November 16, 2011. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

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, on June 26, 2009. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration s New Energy for America Plan that includes, among other provisions, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative 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 will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. 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 permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

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 which recognized the scientific view that the increase in global temperature should be below two degrees Celsius; include a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020; and establish the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. Once 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.

On September 21, 2009, the U.S. Court of Appeals for the Second Circuit and on October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. However, a subsequent ruling from the U.S. Court of Appeals for the Fifth Circuit reinstated the lower court dismissal of a complaint alleging damage from GHG emissions. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. On December 6, 2010, the U.S. Supreme Court granted a writ of certiorari to the Second Circuit in *Connecticut v. AEP*. Briefing and oral argument are expected to be completed in early 2011 and a decision issued in or around June 2011. While FirstEnergy is not a party to this litigation, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

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 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 Clean Water Act and its amendments, apply to FirstEnergy s plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FirstEnergy s operations.

The EPA established new performance standards under Section 316(b) of the Clean Water Act 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). 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. On April 1, 2009, the U.S. Supreme Court reversed one significant aspect of the

Second Circuit s opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. The EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. 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. On November 19, 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by December 31, 2014. 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 June 2008, the U.S. Attorney s Office in Cleveland, Ohio advised FGCO that it is considering prosecution under the Clean Water Act 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. FGCO is unable to predict the outcome of this matter.

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 February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. On May 4, 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. FGCO s future cost of compliance with any coal combustion residuals regulations which 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.

The Utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. 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 December 31, 2010, based on estimates of the total costs of cleanup, the Utilities proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $104 million (JCP&L $69 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $32 million) have been accrued through December 31, 2010. Included in the total are accrued liabilities of approximately $64 million for environmental remediation of former MGPs and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

Fuel Supply

FES currently has long-term coal contracts with various terms to acquire approximately 19.2 million tons of coal for the year 2011, approximately 116% of its 2011 coal requirements of 16.6 million tons. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, West Virginia, Montana and Wyoming. The contracts expire at various times through December 31, 2030. FES has contracted sufficient storage to manage the coal inventory should that be necessary. See Environmental Matters for factors pertaining to meeting environmental regulations affecting coal-fired generating units.

In July 2008, FEV entered into a joint venture with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, to acquire a majority stake in the Bull Mountain Mine Operations, now called Signal Peak, near Roundup, Montana. This joint venture is part of FirstEnergy s strategy to secure high-quality fuel supplies at attractive prices to maximize the capacity of its fossil generating plants. In a related transaction, FGCO entered into a 15-year agreement to purchase up to 10 million tons of bituminous western coal annually from the mine. FirstEnergy also entered into agreements with the rail carriers associated with transporting coal from the mine to its generating stations, and began taking delivery of the coal in late 2009. The joint venture has the right to resell Signal Peak coal tonnage not used at FirstEnergy facilities and has call rights on such coal above certain levels.

FirstEnergy has contracts for all uranium requirements through 2012 and a portion of uranium material requirements through 2024. Conversion services contracts fully cover requirements through 2011 and partially fill requirements through 2024. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2020. A portion of enrichment requirements is also contracted for through 2024. Fabrication services for fuel assemblies are contracted for both Beaver Valley units and Davis-Besse through 2013 and through the current operating license period for Perry. The Davis-Besse fabrication contract also has an extension provision for services for additional consecutive reload batches through the current operating license period. In addition to the existing commitments, FirstEnergy intends to make additional arrangements for the supply of uranium and for the subsequent conversion, enrichment, fabrication, and waste disposal services.

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On-site spent fuel storage facilities are expected to be adequate for Beaver Valley Unit 1 through 2014. Davis-Besse has adequate storage through 2017. FENOC is taking actions to extend the spent fuel storage capacity for Beaver Valley Units 1 and 2 and Perry. Plant modifications to increase the storage capacity of the existing spent fuel storage pool at Beaver Valley Unit 2 are currently under NRC review with approval expected by mid-year 2011. Dry fuel storage is also being pursued at Beaver Valley with completion projected by the end of 2014. Perry dry fuel storage facilities have been completed with the initial dry fuel storage loading pending resolution of a technical issue with the NRC. The Perry initial dry fuel storage loading campaign is targeted for 2012. Both Beaver Valley 2 and Perry maintain sufficient fuel storage capability to continue operations through the targeted completion dates of their respective storage expansion projects. After current on-site storage capacity at the plants is exhausted, additional storage capacity will have to be obtained either through plant modifications, interim off-site disposal, or permanent waste disposal facilities.

The Federal Nuclear Waste Policy Act of 1982 provided for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NGC has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The DOE submitted the license application for Yucca Mountain to the NRC on June 3, 2008. On March 3, 2010, the Department of Energy filed a motion to withdraw its Yucca Mountain license application with prejudice. The Atomic Safety and Licensing Board denied the Department s withdrawal motion on June 29, 2010. That decision is on appeal to the Commission. However, the current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies is being performed.

In parallel, several parties filed actions in the U.S. Circuit Court of Appeals for the D.C. Circuit challenging the Department s authority to withdraw the license application in light of its obligations under the Nuclear Waste Policy Act. The first case filed was *In re: Aiken County*, filed on February 19, 2010. Robert L. Ferguson, et al. filed a petition on February 25, 2010; State of South Carolina filed on March 26, 2010; and State of Washington filed on April 13, 2010. These cases have since been consolidated. Arguments in the case are scheduled for March 22, 2011. In light of this uncertainty, FirstEnergy intends to make additional arrangements for storage capacity as a contingency for the continuing delays of the DOE acceptance of spent fuel for disposal.

Fuel oil and natural gas are used primarily to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so. Requirements are expected to average approximately 5 million gallons per year over the next five years. Natural gas is currently consumed primarily by peaking units and demand is forecasted at less than 1 million mcf in 2011. FirstEnergy purchased a partially completed combined cycle combustion turbine plant in Fremont Ohio. Construction is scheduled to be completed in 2011.

System Demand

The 2010 net maximum hourly demand for each of the Utilities was:

- OE 5,610 MW on July 23, 2010;
- Penn 1,028 MW on July 23, 2010;
- CEI 4,418 MW on July 23, 2010;
- TE 2,122 MW on July 23, 2010;
- JCP&L 6,420 MW on July 6, 2010;
- Met-Ed 2,932 MW on July 6, 2010; and
- Penelec 2,884 MW on July 6, 2010.

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Supply Plan

Regulated Commodity Sourcing

The Utilities have a default service obligation to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L s default service supply is secured through a statewide competitive procurement process approved by the NJBPU. The Ohio Companies and Penn s default service supplies are provided through a competitive procurement process approved by the PUCO and PPUC, respectively. The default service supply for Met-Ed and Penelec was secured through a FERC-approved agreement with FES through 2010, transitioning to a PPUC-approved competitive procurement process in 2011. If any supplier fails to deliver power to any one of the Utilities service areas, the Utility serving that area may need to procure the required power in the market in their role as a POLR.

Unregulated Commodity Sourcing

FES provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES controls 13,236 MW of installed generating capacity. FES supplies the power requirements of its competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

FES has retail and wholesale competitive load-serving obligations in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various POLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2010, FES generation was used to serve two primary obligations affiliated companies utilized approximately 43% of FES total generation and retail customers utilized approximately 43% of FES total generation. Geographically, approximately 60% of FES obligation is located in the MISO market area and 40% is located in the PJM market area.

Regional Reliability

FirstEnergy s operating companies are located within MISO and PJM and operate under the reliability oversight of a regional entity known as Reliability*First*. This regional entity operates under the oversight of the NERC in accordance with a Delegation Agreement approved by the FERC. Reliability*First* began operations under the NERC on January 1, 2006. On July 20, 2006, the NERC was certified by the FERC as the ERO in the United States pursuant to Section 215 of the FPA and Reliability*First* was certified as a regional entity.

Competition

As a result of actions taken by state legislative bodies, major changes in the electric utility business have occurred in portions of the United States, including Ohio, New Jersey and Pennsylvania, where FirstEnergy s utility subsidiaries operate. These changes have altered the way traditional integrated utilities conduct their business. FirstEnergy has aligned its business units to participate in the competitive electricity marketplace (see Management s Discussion and Analysis). FirstEnergy s Competitive Energy Services segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey, and Illinois through FES.

In New Jersey, JCP&L has procured electric generation supply to serve its BGS customers since 2002 through a statewide auction process approved by the NJBPU. The auction is designed to procure supply for BGS customers at a cost reflective of market conditions. In Ohio, SB221 provides two options for pricing generation in 2009 and beyond through a negotiated rate plan or a competitive bidding process (see Ohio Regulatory Matters above). In Pennsylvania, all electric distribution companies are required to secure generation for customers in competitive markets effective January 1, 2011.

Seasonality

The sale of electric power is generally a seasonal business and weather patterns can have a material impact on FirstEnergy s operating results. Demand for electricity in our service territories historically peaks during the summer and winter months, with market prices also generally peaking at that time. Accordingly, FirstEnergy s annual results of operations and liquidity position may depend disproportionately on its operating performance during the summer and winter. Mild weather conditions may result in lower power sales and consequently lower earnings.

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Research and Development

The Utilities, FES, and FENOC participate in the funding of EPRI, which was formed for the purpose of expanding electric research and development (R&D) under the voluntary sponsorship of the nation s electric utility industry public, private and cooperative. Its goal is to mutually benefit utilities and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. EPRI conducts research on all aspects of electric power production and use, including fuels, generation, delivery, energy management and conservation, environmental effects and energy analysis. The majority of EPRI s research and development projects are directed toward practical solutions and their applications to problems currently facing the electric utility industry.

FirstEnergy participates in other initiatives with industry R&D consortiums and universities to address technology needs for its various business units. Participation in these consortiums helps the company address research needs in areas such as plant operations and maintenance, major component reliability, environmental controls, advanced energy technologies, and transmission and distribution system infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

Executive Officers

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander (A)(B)	59	President and Chief Executive Officer	*-present
		Chief Executive Officer (F)	*-present
W. D. Byrd (B)	56	Vice President, Corporate Risk & Chief Risk Officer	2007-present
		Director Rates Strategy	*-2007
L. M. Cavalier (B)	59	Senior Vice President Human Resources	2005-present
		Vice President	*-2005
M. T. Clark (A)(B)(C)(D)(E)(F)	60	Executive Vice President and Chief Financial Officer	2009-present
		Executive Vice President Strategic Planning & Operations	2008-2009
		Senior Vice President Strategic Planning & Operations	*-2008
C. E. Jones (A)(B)	55	Senior Vice President & President FirstEnergy Utilities	2010-present
		President (C) (D)	2010-present
		Senior Vice President Energy Delivery & Customer Service	2009-2010
		President FirstEnergy Solutions	2007-2009
		Senior Vice President Energy Delivery & Customer Service	*-2007
J. H. Lash (F)	60	President and Chief Nuclear Officer	2010-present
		Senior Vice President and Chief Operating Officer	2007-2010
		Vice President, Beaver Valley	*-2007
C. D. Lasky (E)	48	Vice President Fossil Operations	2008-present
		Vice President Fossil Operations & Air Quality Compliance	2007-2008
		Vice President	*-2007
G. R. Leidich (A)(B)	60	Executive Vice President & President FirstEnergy Generation	2008-present
		Senior Vice President Operations (B)	2007-2008
		President and Chief Nuclear Officer (F)	*-2007
D. C. Luff (B)	63	Senior Vice President Governmental Affairs	2007-present
		Vice President	*-2007
J. F. Pearson (A)(B)(C)(D)(E)(F)	56	Vice President and Treasurer	2006-present
		Treasurer	*-2006
D. R. Schneider (E)	49	President	2009-present
		Senior Vice President Energy Delivery & Customer Service (B)	2007-2009
		Vice President (B)	2006-2007
		Vice President (E)	*-2006
L. L. Vespoli (A)(B)(C)(D)(E)(F)	51	Executive Vice President and General Counsel	2008-present
		Senior Vice President and General Counsel	*-2008

H. L. Wagner (A)(B)	58	Vice President, Controller and Chief Accounting Officer	*-present
		Vice President and Controller (C)(D)(E)(F)	*-present

(A) Denotes executive officer of FirstEnergy Corp.

(B) Denotes executive officer of FESC

(C) Denotes executive officer of OE, CEI and TE.

(D) Denotes executive officer of Met-Ed, Penelec and Penn.

(E) Denotes executive officer of FES

(F) Denotes executive officer of FENOC

* Indicates position held at least since January 1, 2006.

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Employees

As of December 31, 2010, FirstEnergy s subsidiaries had a total of 13,330 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	2,796	295
OE	1,227	750
CEI	916	615
TE	394	287
Penn	207	154
JCP&L	1,434	1,097
Met-Ed	706	509
Penelec	899	642
ATSI	39	
FES	274	
FGCO	1,751	1,140
FENOC	2,687	982
Total	13,330	6,471

FirstEnergy Web Site

Each of the registrant s 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, we routinely post important information on our Web site and recognize our Web site is 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 Web site shall not be deemed incorporated into, or to be part of, this report.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management of each Registrant regularly evaluates the most significant risks of the Registrant s businesses and reviews those risks with the FirstEnergy Board of Directors or appropriate Committees of the Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy and our subsidiaries. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we currently consider material. Additional information on risk factors is included in Item 1. Business and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results.

Risks Related to Business Operations

Risks Arising from the Reliability of Our Power Plants and Transmission and Distribution Equipment

Operation of generation, transmission and distribution facilities involves risk, including, the risk of potential breakdown or failure of equipment or processes, due to aging infrastructure, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operating and maintenance costs, purchased power costs and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWH or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. Moreover, if we were unable to perform under contractual obligations, penalties or liability for damages could result. FES, FGCO and the Ohio Companies are exposed to losses under their applicable sale-leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless. Although we believe these types of events are unlikely to occur, FES, FGCO and the Ohio Companies have a maximum exposure to loss under those provisions of approximately $1.36 billion for FES, $666 million for OE and an aggregate of $622 million for TE and CEI as co-lessees.

We remain obligated to provide safe and reliable service to customers within our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards due to a number of factors, including, but not limited to, equipment failure and weather, could adversely affect our operating results through reduced revenues and increased capital and operating costs and the imposition of penalties/fines or other adverse regulatory outcomes.

Changes in Commodity Prices Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive wholesale and retail markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Changes in the market price of electricity, which are affected by changes in other commodity costs and other factors, may impact our results of operations and financial position by increasing the amount we pay to purchase power to supply POLR and default service obligations in the states we do business. In addition, the global economy could lead to lower international demand for coal, oil and natural gas, which may lower fossil fuel prices and put downward pressure on electricity prices.

Electricity and fuel prices may fluctuate substantially over relatively short periods of time for a variety of reasons, including:

- changing weather conditions or seasonality;
- changes in electricity usage by our customers;
- illiquidity and credit worthiness of participants in wholesale power and other markets;
- transmission congestion or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy commodities;
- changes in power production capacity;
- outages at our power production facilities or those of our competitors;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- changes in legislation and regulation; and
- natural disasters, wars, acts of sabotage, terrorist acts, embargoes and other catastrophic events.

We Are Exposed to Operational, Price and Credit Risks Associated With Selling and Marketing Products in the Power Markets That We Do Not Always Completely Hedge Against

We purchase and sell power at the wholesale level under market-based tariffs authorized by the FERC, and also enter into agreements to sell available energy and capacity from our generation assets. If we are unable to deliver firm capacity and energy under these agreements, we may be required to pay damages. These damages would generally be based on the difference between the market price to acquire replacement capacity or energy and the contract price of the undelivered capacity or energy. Depending on price volatility in the wholesale energy markets, such damages could be significant. Extreme weather conditions, unplanned power plant outages, transmission disruptions, and other factors could affect our ability to meet our obligations, or cause increases in the market price of replacement capacity and energy.

We attempt to mitigate risks associated with satisfying our contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy our net firm sales contracts and, when necessary, by purchasing firm transmission service. We also routinely enter into contracts, such as fuel and power purchase and sale commitments, to hedge our exposure to fuel requirements and other energy-related commodities. We may not, however, hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position could be negatively affected.

The Use of Derivative Contracts by Us to Mitigate Risks Could Result in Financial Losses That May Negatively Impact Our Financial Results

We use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. Also, we could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

Financial Derivatives Reforms Could Increase Our Liquidity Needs and Collateral Costs

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to protect.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit, Are by Their Very Nature Risk Related, and We Could Suffer Economic Losses Despite Such Policies

We attempt to mitigate the market risk inherent in our energy, fuel and debt positions. Procedures have been implemented to enhance and monitor compliance with our risk management policies, including validation of transaction and market prices, verification of risk and transaction limits, sensitivity analysis and daily portfolio reporting of various risk measurement metrics. Nonetheless, we cannot economically hedge all of our exposures in these areas and our risk management program may not operate as planned. For example, actual electricity and fuel prices may be significantly different or more volatile than the historical trends and assumptions reflected in our analyses. Also, our power plants might not produce the expected amount of power during a given day or time period due to weather conditions, technical problems or other unanticipated events, which could require us to make energy purchases at higher prices than the prices under our energy supply contracts. In addition, the amount of fuel required for our power plants during a given day or time period could be more than expected, which could require us to buy additional fuel at prices less favorable than the prices under our fuel contracts. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge.

Our risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

We also face credit risks from parties with whom we contract who could default in their performance, in which cases we could be forced to sell our power into a lower-priced market or make purchases in a higher-priced market than existed at the time of executing the contract. Although we have established risk management policies and programs, including credit policies to evaluate counterparty credit risk, there can be no assurance that we will be able to fully meet our obligations, that we will not be required to pay damages for failure to perform or that we will not experience counterparty non-performance or that we will collect for voided contracts. If counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices. In that event, our financial results could be adversely affected.

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Nuclear Generation Involves Risks that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning

We are subject to the risks of nuclear generation, including but not limited to the following:

- the potential harmful effects on the environment and human health resulting from unplanned radiological releases associated with the operation of our nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- uncertainties with respect to contingencies and assessments if insurance coverage is inadequate; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed operation including increases in minimum funding requirements or costs of completion.

The NRC has broad authority under federal law to impose licensing security and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Also, a serious nuclear incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit.

Our nuclear facilities are insured under NEIL policies issued for each plant. Under these policies, up to $2.8 billion of insurance coverage is provided for property damage and decontamination and decommissioning costs. We have also obtained approximately $2.0 billion of insurance coverage for replacement power costs. Under these policies, we can be assessed a maximum of approximately $79 million for incidents at any covered nuclear facility occurring during a policy year that are in excess of accumulated funds available to the insurer for paying losses.

The Price-Anderson Act limits the public liability that can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate in the United States) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $12.2 billion provided by an industry retrospective rating plan. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $118 million (but not more than $18 million per year) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Our maximum potential exposure under these provisions would be $470 million per incident but not more than $70 million in any one year.

Capital Market Performance and Other Changes May Decrease the Value of Decommissioning Trust Fund, Pension Fund Assets and Other Trust Funds Which Then Could Require Significant Additional Funding

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generation facilities and under pension and other post-retirement benefit plans. The value of certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission nuclear generating stations, to pay future pensions and other obligations requires significant judgment, and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or greater liability levels can negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets and the States in Which We Do Business

As a result of the EPACT, owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by the NERC and approved by FERC as well as mandatory reliability standards and energy efficiency requirements imposed by each of the states in which we operate. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Reliability standards that were historically subject to voluntary compliance are now mandatory and could subject us to potential civil penalties for violations which could negatively impact our business. The FERC can now impose penalties of $1.0 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by the FERC and the states, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the potential exercise of market power and to ensure the market functions. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, the RTOs may direct our transmission owning affiliates to build new transmission facilities to meet the reliability requirements of the RTO or to provide new or expanded transmission service under the RTO tariffs.

We Rely on Transmission and Distribution Assets That We Do Not Own or Control to Deliver Our Wholesale Electricity. If Transmission is Disrupted Including Our Own Transmission, or Not Operated Efficiently, or if Capacity is Inadequate, Our Ability to Sell and Deliver Power May Be Hindered

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity we sell. If transmission is disrupted (as a result of weather, natural disasters or other reasons) or not operated efficiently by independent system operators, in applicable markets, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered, or we may be unable to sell products on the most favorable terms. In addition, in certain of the markets in which we operate, we may be required to pay for congestion costs if we schedule delivery of power between congestion zones during periods of high demand. If we are unable to hedge or recover for such congestion costs in retail rates, our financial results could be adversely affected.

Demand for electricity within our Utilities service areas could stress available transmission capacity requiring alternative routing or curtailing electricity usage that may increase operating costs or reduce revenues with adverse impacts to results of operations. In addition, as with all utilities, potential concerns over transmission capacity could result in MISO, PJM or the FERC requiring us to upgrade or expand our transmission system, requiring additional capital expenditures.

The FERC requires wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, it is possible that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electricity as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets or whether independent system operators in applicable markets will operate the transmission networks, and provide related services, efficiently.

Disruptions in Our Fuel Supplies Could Occur, Which Could Adversely Affect Our Ability to Operate Our Generation Facilities and Impact Financial Results

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations. Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. Although we have long-term contracts in place for our coal and coal transportation needs, power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. If prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Temperature Variations as well as Weather Conditions or other Natural Disasters Could Have a Negative Impact on Our Results of Operations and Demand Significantly Below or Above Our Forecasts Could Adversely Affect Our Energy Margins

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snow storms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. Customer demand could change as a result of severe weather conditions or other circumstances over which we have no control. We satisfy our electricity supply obligations through a portfolio approach of providing electricity from our generation assets, contractual relationships and market purchases. A significant increase in demand could adversely affect our energy margins if we are required under the terms of the default service tariffs to provide the energy supply to fulfill this increased demand at capped rates, which we expect would remain below the wholesale prices at which we would have to purchase the additional supply if needed or, if we had available capacity, the prices at which we could otherwise sell the additional supply. Accordingly, any significant change in demand could have a material adverse effect on our results of operations and financial position.

We Are Subject to Financial Performance Risks Related to Regional and General Economic Cycles and also Related to Heavy Manufacturing Industries such as Automotive and Steel

Our business follows the economic cycles of our customers. As our retail strategy is centered around the sale of output from our generating plants generally where that power will reach, therefore, we are more directly impacted by the economic conditions in our primary markets (i.e., Pennsylvania, Ohio, Maryland, New Jersey, Michigan and Illinois). Declines in demand for electricity as a result of a regional economic downturn would be expected to reduce overall electricity sales and reduce our revenues. Electric generation sales volume has been, and is expected to continue to be, influenced by circumstances in automotive, steel and other heavy industries.

Increases in Customer Electric Rates and Economic Uncertainty May Lead to a Greater Amount of Uncollectible Customer Accounts

Our operations are impacted by the economic conditions in our service territories and those conditions could negatively impact the rate of delinquent customer accounts and our collections of accounts receivable which could adversely impact our financial condition, results of operations and cash flows.

The Goodwill of One or More of Our Operating Subsidiaries May Become Impaired, Which Would Result in Write-Offs of the Impaired Amounts

Goodwill could become impaired at one or more of our operating subsidiaries. The actual timing and amounts of any goodwill impairments in future years would depend on many uncertainties, including changing interest rates, utility sector market performance, our capital structure, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable utility acquisitions, environmental regulations and other factors.

We Face Certain Human Resource Risks Associated with the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements

We must find ways to retain our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Mitigating these risks could require additional financial commitments.

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Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. However, we expect cost pressures could increase as we continue to implement our retail sales strategy. We expect to continue to face increased cost pressures in the areas of health care and pension costs. We have experienced significant health care cost inflation in the last few years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken and expect to take requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. If actual results differ materially from our assumptions, our costs could be significantly increased.

Our Business is Subject to the Risk that Sensitive Customer Data May be Compromised, Which Could Result in an Adverse Impact to Our Reputation and/or Results of Operations

Our business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business. A security breach may occur, despite security measures taken by us and required of vendors. If a significant or widely publicized breach occurred, our business reputation may be adversely affected, customer confidence may be diminished, or we may become subject to legal claims, fines or penalties, any of which could have a negative impact on our business and/or results of operations.

Acts of War or Terrorism Could Negatively Impact Our Business

The possibility that our infrastructure, such as electric generation, transmission and distribution facilities, or that of an interconnected company, could be direct targets of, or indirect casualties of, an act of war or terrorism, could result in disruption of our ability to generate, purchase, transmit or distribute electricity. Any such disruption could result in a decrease in revenues and additional costs to purchase electricity and to replace or repair our assets, which could have a material adverse impact on our results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters

Our business plan calls for extensive capital investments. We may be exposed to the risk of substantial price increases in the costs of labor and materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This could have negative financial impacts such as incurring losses or delays in completing construction projects.

Changes in Technology May Significantly Affect Our Generation Business by Making Our Generating Facilities Less Competitive

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies will reduce their costs to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

We May Acquire Assets That Could Present Unanticipated Issues for Our Business in the Future, Which Could Adversely Affect Our Ability to Realize Anticipated Benefits of Those Acquisitions

Asset acquisitions involve a number of risks and challenges, including: management attention; integration with existing assets; difficulty in evaluating the requirements associated with the assets prior to acquisition, operating costs, potential environmental and other liabilities, and other factors beyond our control; and an increase in our expenses and working capital requirements. Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize other anticipated benefits from any such asset acquisition.

Ability of Certain FirstEnergy Companies to Meet Their Obligations to Other FirstEnergy Companies

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies because of transactions involving energy, coal, other commodities, services, and because of hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, resulting in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Our hedging activities are generally undertaken with a view to overall FirstEnergy exposures. Some FirstEnergy companies may therefore be more or less hedged than if they were to engage in such transactions alone.

Risks Associated With Our Proposed Merger With Allegheny

We May be Unable to Obtain the Approvals Required to Complete Our Merger with Allegheny or, in Order to do so, the Combined Company May be Required to Comply With Material Restrictions or Conditions

On February 11, 2010, we announced the execution of a merger agreement with Allegheny. The only regulatory approval pending is from the PPUC. The PPUC could impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either us or Allegheny to abandon the merger.

If Completed, Our Merger with Allegheny May Not Achieve Its Intended Results

We and Allegheny entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies relating to both the regulated utility operations and the generation business. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the business of Allegheny is integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management s time and energy and could have an adverse effect on the combined company s business, financial results and prospects.

We Will be Subject to Business Uncertainties and Contractual Restrictions While the Merger with Allegheny is Pending That Could Adversely Affect Our Financial Results

Uncertainty about the effect of the merger with Allegheny on employees and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be affected.

The pursuit of the merger and the preparation for the integration of Allegheny into our company may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect our financial results.

In addition, the merger agreement restricts us, without Allegheny s consent, from making certain acquisitions and taking other specified actions until the merger occurs or the merger agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

Failure to Complete Our Merger with Allegheny Could Negatively Impact Our Stock Price and Our Future Business and Financial Results

If our merger with Allegheny is not completed, our ongoing business and financial results may be adversely affected and we would be subject to a number of risks, including the following:

We may be required, under specified circumstances set forth in the Merger Agreement, to pay Allegheny a termination fee of $350 million and/or Allegheny s reasonable out-of-pocket transaction expenses up to $45 million;

we would be required to pay costs relating to the merger, including legal, accounting, financial advisory, filing and printing costs, whether or not the merger is completed; and

matters relating to our merger with Allegheny (including integration planning) may require substantial commitments of time and resources by our management, which could otherwise have been devoted to other opportunities that may have been beneficial to us.

We could also be subject to litigation related to any failure to complete our merger with Allegheny. If our merger is not completed, these risks may materialize and may adversely affect our business, financial results and stock price.

Risks Associated With Regulation

Complex and Changing Government Regulations Could Have a Negative Impact on Our Results of Operations

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influence our operating environment. Changes in, or reinterpretations of, existing laws or regulations, or the imposition of new laws or regulations, could require us to incur additional costs or change the way we conduct our business, and therefore could have an adverse impact on our results of operations.

Our utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may or may not be set to recover its expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. For example, we may be unable to timely recover the costs for our energy efficiency investments, expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner. For example, our utility subsidiaries ability to timely recover rates and charges associated with integration of the ATSI footprint into PJM is uncertain.

Regulatory Changes in the Electric Industry, Including a Reversal, Discontinuance or Delay of the Present Trend Toward Competitive Markets, Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of restructuring initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including the states in which we do business. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities conduct their business.

Some states that have deregulated generation service have experienced difficulty in transitioning to market-based pricing. In some instances, state and federal government agencies and other interested parties have made proposals to impose rate cap extensions or otherwise delay market restructuring or even re-regulate areas of these markets that have previously been deregulated. Although we expect wholesale electricity markets to continue to be competitive, proposals to re-regulate our industry may be made, and legislative or other action affecting the electric power restructuring process may cause the process to be delayed, discontinued or reversed in the states in which we currently, or may in the future, operate. Such delays, discontinuations or reversals of electricity market restructuring in the markets in which we operate could have an adverse impact on our results of operations and financial condition.

The FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry. If the restructuring, deregulation or re-regulation efforts result in decreased margins or unrecoverable costs, our business and results of operations would be adversely affected. We cannot predict the extent or timing of further efforts to restructure, deregulate or re-regulate our business or the industry.

The Prospect of Rising Rates Could Prompt Legislative or Regulatory Action to Restrict or Control Such Rate Increases. This In Turn Could Create Uncertainty Affecting Planning, Costs and Results of Operations and May Adversely Affect the Utilities Ability to Recover Their Costs, Maintain Adequate Liquidity and Address Capital Requirements

Increases in utility rates, such as may follow a period of frozen or capped rates, can generate pressure on legislators and regulators to take steps to control those increases. Such efforts can include some form of rate increase moderation, reduction or freeze. The public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues, and the ability to recover costs. Such uncertainty restricts flexibility and resources, given the need to plan and ensure available financial resources. Such uncertainty also affects the costs of doing business. Such costs could ultimately reduce liquidity, as suppliers tighten payment terms, and increase costs of financing, as lenders demand increased compensation or collateral security to accept such risks.

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Our Profitability is Impacted by Our Affiliated Companies Continued Authorization to Sell Power at Market-Based Rates

The FERC granted FES, FGCO and NGC authority to sell electricity at market-based rates. These orders also granted them waivers of certain FERC accounting, record-keeping and reporting requirements. The Utilities also have market-based rate authority. The FERC s orders that grant this market-based rate authority reserve the right to revoke or revise that authority if the FERC subsequently determines that these companies can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. As a condition to the orders granting the generating companies market-based rate authority, every three years they are required to file a market power update to show that they continue to meet the FERC s standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. FES, FGCO, NGC and the Utilities renewed this authority for PJM in 2008 and MISO in 2009. On December 30, 2010, FES, FGCO, NGC and the Utilities filed to renew this authority for operations within PJM. If any of these companies were to lose their market-based rate authority, they would be required to obtain the FERC s acceptance to sell power at cost-based rates. FES, FGCO and NGC could also lose their waivers, and become subject to the accounting, record-keeping and reporting requirements that are imposed on utilities with cost-based rate schedules.

There Are Uncertainties Relating to Our Participation in RTOs

RTO rules could affect our ability to sell power produced by our generating facilities to users in certain markets due to transmission constraints and attendant congestion costs. The prices in day-ahead and real-time energy markets and RTO capacity markets have been subject to price volatility. Administrative costs imposed by RTOs, including the cost of administering energy markets, have also increased. The rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. To the degree we incur significant additional fees and increased costs to participate in an RTO, and we are limited with respect to recovery of such costs from retail customers, we may suffer financial harm. While RTO rates for transmission service are cost based, our revenues from customers to whom we currently provide transmission services may not reflect all of the administrative and market-related costs imposed under the RTO tariff. In addition, we may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Finally, we may be required to expand our transmission system according to decisions made by an RTO rather than our internal planning process. As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO s market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.

The MISO has proposed changes to its rates and tariffs that may result or cause significant charges to ATSI or the Ohio Companies or Penn upon their respective withdrawal from the MISO on May 31, 2011. The implementation of these and other new market designs has the potential to increase our costs of transmission, costs associated with inefficient generation dispatching, costs of participation in the market and costs associated with estimated payment settlements.

Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will ultimately develop and operate, or what region they will cover, we cannot fully assess the impact that these power markets or other ongoing RTO developments may have.

A Significant Delay in or Challenges to Various Elements of ATSI s Consolidation into PJM, including but not Limited to, the Intervention of Parties to the Regulatory Proceedings Could have a Negative Impact on Our Results of Operations and Financial Condition

On December 17, 2009, FERC authorized, subject to certain conditions, FirstEnergy to consolidate its transmission assets and operations that currently are located in MISO into PJM; such consolidation to be effective on June 1, 2011. The consolidation will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Consolidation on June 1, 2011 will coincide with delivery of power under the next competitive generation procurement process for the Ohio Companies. On December 17, 2009, and after FERC issued the order, ATSI executed and delivered to PJM those legal documents necessary to implement its consolidation into PJM. On December 18, 2009, the Ohio Companies and Penn executed and delivered to PJM those legal documents necessary to follow ATSI into PJM. Currently, ATSI, the Ohio Companies and Penn are expected to consolidate into PJM as planned on June 1, 2011.

On February 1, 2011, ATSI filed its proposal with FERC for moving its transmission rate into PJM s tariffs. Numerous parties are expected to intervene and file responsive comments. Our expectation is that ATSI will enter PJM as scheduled on June 1, 2011, and that if legal proceedings regarding its rate are outstanding at that time, ATSI will be permitted to start charging its proposed rates, subject to refund. Additional FERC proceedings are either pending or expected in which the amount of exit fees, transmission cost allocations, and costs associated with long term firm transmission rights payable by the ATSI zone upon its departure from the Midwest ISO will be determined. In addition, certain other parties continue to protest aspects of the move into PJM, and certain of these matters remain outstanding and will be resolved in future FERC proceedings. A ruling by FERC or any other regulator with jurisdiction in favor of one or more of the intervening or protesting parties (and against FirstEnergy) on one or more of the disputed issues could result in a negative impact on our results of operations and financial condition.

Energy Conservation and Energy Price Increases Could Negatively Impact Our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact our financial results in different ways. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, the value of our merchant generation and other unregulated business activities could be adversely impacted. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery timeframe in Ohio and Pennsylvania. In New Jersey, we recover the costs for energy efficiency programs through the SBC. Currently only Ohio has provisions for recovery of lost revenues. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We could also be impacted if any future energy price increases result in a decrease in customer usage. Our results could be affected if we are unable to increase our customer s participation in our energy efficiency programs. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Our Business and Activities are Subject to Extensive Environmental Requirements and Could be Adversely Affected by such Requirements

We may be forced to shut down facilities, either temporarily or permanently, if we are unable to comply with certain environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are uneconomical. In fact, we are exposed to the risk that such electric generating plants would not be permitted to continue to operate if pollution control equipment is not installed by prescribed deadlines.

The EPA is Conducting NSR Investigations at a Number of Our Generating Plants, the Results of Which Could Negatively Impact Our Results of Operations and Financial Condition

We may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations. For example, applicable standards under the EPA s NSR initiatives remain in flux. Under the CAA, modification of our generation facilities in a manner that causes increased emissions could subject our existing facilities to the far more stringent NSR standards applicable to new facilities.

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The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work believed by the companies to be routine maintenance. We are currently involved in litigation and EPA investigations concerning alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position in these environmental matters but FGCO is unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition. For a more complete discussion see Environmental Matters.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with Future Environmental Laws, Including Limitations on GHG Emissions, Could Adversely Affect Cash Flow and Profitability

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for environmental monitoring, installation of pollution control equipment, emission fees, maintenance, upgrading, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. If the cost of compliance with existing environmental laws and regulations does increase, it could adversely affect our business and results of operations, financial position and cash flows. Moreover, changes in environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of generation, we may not directly recover through rates additional costs incurred for such compliance. Our compliance strategy, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control or new interpretations of longstanding requirements, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on carbon dioxide emissions from power generation facilities and their potential role in climate change. Many states and environmental groups have also challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. Also, claims have been made alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damage from exposure to hazardous materials. Recently the courts have begun to acknowledge these claims and may order us to reduce GHG emissions in the future. There is a growing consensus in the United States and globally that GHG emissions are a major cause of global warming and that some form of regulation will be forthcoming at the federal level with respect to GHG emissions (including carbon dioxide) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances. As a result, it is possible that state and federal regulations will be developed that will impose more stringent limitations on emissions than are currently in effect. In December 2009, the EPA issued an endangerment and cause or contributing finding for GHG under the CAA, which will allow the EPA to craft rules that directly regulate GHG. This finding triggered several regulatory actions under the CAA, resulting, among other things in the regulation of GHG emissions from large stationary sources. Although several bills have been introduced at the state and federal level that would compel carbon dioxide emission reductions, none have advanced through the legislature. Due to the uncertainty of control technologies available to reduce greenhouse gas emissions including CO_2, as well as the unknown nature of potential compliance obligations should climate change regulations be enacted, we cannot provide any assurance regarding the potential impacts these future regulations would have on our operations. In addition, any legal obligation that would require us to substantially reduce our emissions could require extensive mitigation efforts and, in the case of carbon dioxide legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Until specific regulations are promulgated, the impact that any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation may have on our results of operations, financial condition or liquidity is not determinable.

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, on June 26, 2009. The Senate continues to consider a number of measures to regulate GHG emissions. President Obama has announced his Administration s New Energy for America Plan that includes, among other provisions, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative 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 GHG emissions commencing in 2010 and begin to submit reports commencing in 2011. 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 May 2010, the EPA finalized new thresholds for GHG emissions that define when permits under the CAA s NSR program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s PSD program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

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 which recognized the scientific view that the increase in global temperature should be below two degrees Celsius; include a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020; and establish the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. Once 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.

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 regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

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 vacated CAIR in its entirety and directed the EPA to redo its analysis from the ground up. In December 2008, the Court reconsidered its prior ruling and 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 opinion. In July 2010, the EPA proposed the CATR to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NOx emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NOx and SO_2 emission allowances between power plants located in the same state and severely limits interstate trading of NOx and SO_2 emission allowances. The EPA also requested comment on two alternative approaches the first eliminates interstate trading of NOx and SO_2 emission allowances and the second eliminates trading of NOx and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial.

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NO_X emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups, vacated the CAMR, ruling that the EPA failed to take the necessary steps to de-list coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers, including boilers which do not use fossil fuels. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. On January 20, 2011, the U.S. District Court for the District of Columbia denied a motion by the EPA for an extension of the deadline to issue final rules, ordering the EPA to issue such rules by February 21, 2011. The EPA also entered into a consent decree requiring it to propose MACT regulations for mercury and other hazardous air pollutants from electric generating units by March 16, 2011, and to finalize the regulations by November 16, 2011. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to FirstEnergy s plants. In addition, various states have water quality standards applicable to FirstEnergy s operations.

The EPA established new performance standards under Section 316(b) of the Clean Water Act 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). 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. On April 1, 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit s opinion and decided that Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. The EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. 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. On November 19, 2010, the Ohio EPA issued a permit for the Bay Shore power plant requiring installation of reverse louvers in its entire water intake channel by April 1, 2013. 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. Also, If either the federal or state final regulations require retrofitting of cooling water intake structures (cooling towers) at any of our power plants, and if installation of such cooling towers is not technically or economically feasible, we may be forced to take actions which could adversely impact our results of operations and financial condition.

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 February 2009, the EPA requested comments from the states on options for regulating coal combustion residuals, including whether they should be regulated as hazardous or non-hazardous waste.

On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. On May 4, 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. FGCO s future cost of compliance with any coal combustion residuals regulations which 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.

The Physical Risks Associated with Climate Change May Impact Our Results of Operations and Cash Flows.

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Finally, climate change could affect the availability of a secure and economical supply of water in some locations, which is essential for continued operation of generating plants.

Remediation of Environmental Contamination at Current or Formerly Owned Facilities

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. Remediation activities associated with our former MGP operations are one source of such costs. We are currently involved in a number of proceedings relating to sites where other hazardous substances have been deposited and may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material.

In some cases, a third party who has acquired assets from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee.

Availability and Cost of Emission Credits Could Materially Impact Our Costs of Operations

We are required to maintain, either by allocation or purchase, sufficient emission credits to support our operations in the ordinary course of operating our power generation facilities. These credits are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances of emission credits, we may be forced to purchase such credits on the open market, which could be costly. If we are unable to maintain sufficient emission credits to match our operational needs, we may have to curtail our operations so as not to exceed our available emission credits, or install costly new emissions controls. As we use the emissions credits that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such credits are available for purchase, but only at significantly higher prices, the purchase of such credits could materially increase our costs of operations in the affected markets. Laws and regulations such as CAIR may, and are, being revised and as CAIR is being rewritten it is creating uncertainty in many areas, including but not limited to, the annual NOx emission allowances beyond 2010.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

If federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation would not also provide for adequate cost recovery, it could result in significant changes in our business, including renewable energy credit purchase costs, purchased power and potentially renewable energy credit costs and capital expenditures. We are unable to predict what impact, if any, these changes may have on our financial condition or results of operations.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities

We have been named as a defendant in pending asbestos litigation involving multiple plaintiffs and multiple defendants. In addition, asbestos and other regulated substances are, and may continue to be, present at our facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us.

The Continuing Availability and Operation of Generating Units is Dependent on Retaining the Necessary Licenses, Permits, and Operating Authority from Governmental Entities, Including the NRC

We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of any of these agencies and we are not assured that any such permits, approvals or certifications will be renewed.

Future Changes in Financial Accounting Standards May Affect Our Reported Financial Results

The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position. The SEC has announced a work plan to aid in its evaluation of the impact that the use of IFRS by U.S. public companies would have on the U.S. securities market. Given the results of the work plan, the SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS. We are currently assessing the impact that this potential change would have on our consolidated financial statements and we will continue to monitor the development of the potential implementation of IFRS.

Increases in Taxes and Fees.

Due to the revenue needs of the United States and the states and jurisdictions in which we operate, various tax and fee increases may be proposed or considered. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, whether any such legislation or regulation will be passed by the state legislatures or regulatory bodies. If enacted, these changes could increase tax costs and could have a negative impact on our results of operations, financial condition and cash flows.

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Risks Associated With Financing and Capital Structure

Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our Financing Costs, Our Ability to Access Capital and Our Requirement to Post Collateral

We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Past disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for certain of our variable interest rate debt securities and failed remarketings (all of which were eventually remarketed) of variable interest rate tax-exempt debt issued to finance certain of our facilities. Continuation of these disruptions could increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that our risk management processes were not established to address. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. A rating downgrade would also increase the fees we pay on our various credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital. On February 11, 2010, S&P issued a report lowering FirstEnergy s and its subsidiaries credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral. Moody s and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. On September 28, 2010, S&P then affirmed the ratings and stable outlook of FE and its subsidiaries. On December 15, 2010, Fitch revised its outlook on FE and FES from stable to negative and affirmed the rating for FirstEnergy and its subsidiaries.

A rating is not a recommendation to buy, sell or hold debt, inasmuch as such rating does not comment as to market price or suitability for a particular investor. The ratings assigned to our debt address the likelihood of payment of principal and interest pursuant to their terms. A rating may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating that may be assigned to our securities. Also, we cannot predict how rating agencies may modify their evaluation process or the impact such a modification may have on our ratings.

Our credit ratings also govern the collateral provisions of certain contract guarantees. Subsequent to the occurrence of a credit rating downgrade to below investment grade or a material adverse event, the immediate posting of cash collateral may be required. See Note 15(B) of the Notes to the Consolidated Financial Statements for more information associated with a credit ratings downgrade leading to the posting of cash collateral.

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on Our Utility Subsidiaries Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Financial Condition

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Our utility subsidiaries are regulated by various state utility commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state commissions could attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends or otherwise restrict cash payments to us.

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts they May be Paid

Our Board of Directors regularly evaluates our common stock dividend policy and determines the dividend rate each quarter. The level of dividends will continue to be influenced by many factors, including, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Disruptions in the Capital and Credit Markets May Adversely Affect Our Business, Including the Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments, Our Ability to Hedge Effectively Our Generation Portfolio, and the Competitiveness and Liquidity of Energy Markets; Each Could Adversely Affect Our Results of Operations, Cash Flows and Financial Condition

We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. Disruptions in the capital and credit markets could adversely affect our ability to draw on our respective credit facilities. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time.

Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash.

The strength and depth of competition in energy markets depends heavily on active participation by multiple counterparties, which could be adversely affected by disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows.

Questions Regarding the Soundness of Financial Institutions or Counterparties Could Adversely Affect Us

We have exposure to many different financial institutions and counterparties and we routinely execute transactions with counterparties in connection with our hedging activities, including brokers and dealers, commercial banks, investment banks and other institutions and industry participants. Many of these transactions expose us to credit risk in the event that any of our lenders or counterparties are unable to honor their commitments or otherwise default under a financing agreement. We also deposit cash balances in short-term investments. Our ability to access our cash quickly depends on the soundness of the financial institutions in which those funds reside. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utilities (other than ATSI and JCP&L), FGCO s and NGC s respective first mortgage indentures constitute, in the opinion of their counsel, direct first liens on substantially all of the respective Utilities , FGCO s and NGC s physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See the Leases and Capitalization notes to the respective financial statements for information concerning leases and financing encumbrances affecting certain of the Utilities , FGCO s and NGC s properties.

FirstEnergy controls the following generation sources as of January 31, 2011, shown in the table below. Except for the leasehold interests, OVEC participation and purchased wind power referenced in the footnotes to the table, substantially all of the generating units are owned by NGC (nuclear) and FGCO (non-nuclear).

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Plant-Location	**Unit**	**Net Demonstrated Capacity (MW)**
Coal-Fired Units		
Ashtabula-		
Ashtabula, OH	5	244
Bay Shore-		
Toledo, OH	1-4	631
R. E. Burger-		
Shadyside, OH	3	94
Eastlake-Eastlake, OH	1-5	1,233
Lakeshore-		
Cleveland, OH	18	245
Bruce Mansfield-	1	830(a)
Shippingport, PA	2	830(b)
	3	830(c)
W. H. Sammis Stratton, OH	1-7	2,220
Kyger Creek Cheshire, OH	1-5	50(d)
Clifty Creek Madison, IN	1-6	60(d)
Total		7,267
Nuclear Units		
Beaver Valley-	1	911
Shippingport, PA	2	904(e)
Davis-Besse-		
Oak Harbor, OH	1	908
Perry-		
N. Perry Village, OH	1	1,268(f)
Total		3,991
Oil/Gas Fired/ Pumped Storage Units		
Richland Defiance, OH	1-6	432
Seneca Warren, PA	1-3	451
West Lorain Lorain, OH	1-6	545
Yard s Creek Blairstown Twp., NJ	1-3	200(g)
Wind power		376(h)
Other		174
Total		2,178
Grand Total		13,436

(a) Includes FGCO s leasehold interest of 93.825% (779 MW) and CEI s leasehold interest of 6.175% (51 MW), which has been assigned to FGCO.

(b) Includes CEI s and TE s leasehold interests of 27.17% (226 MW) and 16.435% (136 MW), respectively, which have been assigned to FGCO.

(c) Includes CEI s and TE s leasehold interests of 23.247% (193 MW) and 18.915% (157 MW), respectively, which have been assigned to FGCO.

(d) Represents FGCO s 4.85% entitlement based on its participation in OVEC.

(e) Includes OE s leasehold interest of 16.65% (151 MW) from non-affiliates.

(f) Includes OE s leasehold interest of 8.11% (103 MW) from non-affiliates.

(g) Represents JCP&L s 50% ownership interest.

(h) Includes 167 MW from leased facilities and 209 MW under power purchase agreements.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. The Utilities overhead and underground transmission lines aggregate 14,932 pole miles.

The Utilities electric distribution systems include 194,685 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of 85,247,000 kV-amperes.

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The transmission facilities that are owned by ATSI are currently operated on an integrated basis as part of MISO through May 31, 2011. Effective June 1, 2011, the ATSI transmission assets will be migrated from MISO and integrated into PJM. The transmission facilities of JCP&L, Met-Ed and Penelec are physically interconnected and are operated on an integrated basis as part of PJM.

FirstEnergy s distribution and transmission systems as of December 31, 2010, consist of the following:

	Distribution Lines	Transmission Lines	Substation Transformer Capacity**
OE	62,156	461	8,300,000
Penn	13,389	52	1,351,000
CEI	33,210		8,754,000
TE	17,592	81	2,497,000
JCP&L	22,668	2,549	20,078,000
Met-Ed	18,641	1,405	8,595,000
Penelec	27,029	2,860	12,409,000
ATSI*		7,524	23,263,000
Total	194,685	14,932	85,247,000

* Represents transmission lines of 69kV and above located in the service areas of OE, Penn, CEI and TE.

** Top rating of in-service power transformers only. Excludes grounding banks, station power transformers, and generator and customer-owned transformers.

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ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 14, Commitments, Guarantees and Contingencies, of FirstEnergy s Notes to Consolidated Financial Statements contained in Item 8 for a description of certain legal proceedings involving FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec.

ITEM 4. REMOVED AND RESERVED

PART II

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

The information required by Item 5 regarding FirstEnergy s market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included in Item 6.

Information for FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec is not disclosed because they are wholly owned subsidiaries of FirstEnergy and there is no market for their common stock.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy s 2011 proxy statement filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock during the fourth quarter of 2010.

	Period			
	October	**November**	**December**	**Fourth Quarter**
Total Number of Shares Purchased[a]	68,246	133,762	539,703	741,711
Average Price Paid per Share	$ 38.50	$ 35.99	$ 35.48	$ 35.85
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs				
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs				

(a) Share amounts reflect purchases on the open market to satisfy FirstEnergy s obligations to deliver common stock under its 2007 Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted under the 2007 Incentive Compensation Plan and the Executive Deferred Compensation Plan.

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ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Revenues	$ 13,339	$ 12,973	$ 13,627	$ 12,802	$ 11,501
Income From Continuing Operations	$ 784	$ 1,006	$ 1,342	$ 1,309	$ 1,258
Earnings Available to FirstEnergy Corp.	$ 784	$ 1,006	$ 1,342	$ 1,309	$ 1,254
Basic Earnings per Share of Common Stock:					
Income from continuing operations	$ 2.58	$ 3.31	$ 4.41	$ 4.27	$ 3.85
Earnings per basic share	$ 2.58	$ 3.31	$ 4.41	$ 4.27	$ 3.84
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	$ 2.57	$ 3.29	$ 4.38	$ 4.22	$ 3.82
Earnings per diluted share	$ 2.57	$ 3.29	$ 4.38	$ 4.22	$ 3.81
Dividends Declared per Share of Common Stock(1)	$ 2.20	$ 2.20	$ 2.20	$ 2.05	$ 1.85
Total Assets	$ 34,805	$ 34,304	$ 33,521	$ 32,311	$ 31,196
Capitalization as of December 31:					
Total Equity	$ 8,513	$ 8,557	$ 8,315	$ 9,007	$ 9,069
Long-Term Debt and Other Long-Term Obligations	12,579	12,008	9,100	8,869	8,535
Total Capitalization	$ 21,092	$ 20,565	$ 17,415	$ 17,876	$ 17,604
Weighted Average Number of Basic Shares Outstanding	304	304	304	306	324
Weighted Average Number of Diluted Shares Outstanding	305	306	307	310	327

(1) Dividends declared in 2010, 2009 and 2008 include four quarterly dividends of $0.55 per share. Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share in 2008. Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share in 2007.

PRICE RANGE OF COMMON STOCK

The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol FE and is traded on other registered exchanges.

	2010		2009	
First Quarter High-Low	$ 47.09	$ 38.31	$ 53.63	$ 35.63
Second Quarter High-Low	$ 39.96	$ 33.57	$ 43.29	$ 35.26

Third Quarter High-Low	$	39.06	$	34.51	$	47.82	$	36.73
Fourth Quarter High-Low	$	40.12	$	35.00	$	47.77	$	41.57
Yearly High-Low	$	47.09	$	33.57	$	53.63	$	35.26

Prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2005 in FirstEnergy s common stock compared with the total cumulative returns of EEI s Index of Investor-Owned Electric Utility Companies and the S&P 500.

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HOLDERS OF COMMON STOCK

There were 105,822 and 105,518 holders of 304,835,407 shares of FirstEnergy s common stock as of December 31, 2010 and January 31, 2011, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11 to the consolidated financial statements.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management s intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms anticipate, potential, expect, believe, estimate and similar words. Forward-lo 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 in the various states in which we do business.

Business and regulatory impacts from ATSI s realignment into PJM Interconnection, L.L.C., economic or weather conditions affecting future sales and margins.

Changes in markets for energy services.

Changing energy and commodity market prices and availability.

Financial derivative reforms that could increase our liquidity needs and collateral costs, replacement power costs being higher than anticipated or inadequately hedged.

The continued ability of FirstEnergy s 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 and coal combustion residual regulations.

The potential impacts of any laws, rules or regulations that ultimately replace CAIR.

The uncertainty of the timing and amounts of the capital expenditures needed to resolve any NSR litigation or other potential similar regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units).

Adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC.

Adverse legal decisions and outcomes related to Met-Ed s and Penelec s transmission service charge appeal at the Commonwealth Court of Pennsylvania.

Any impact resulting from the receipt by Signal Peak of the Department of Labor s notice of a potential pattern of violations at Bull Mountain Mine No.1.

The continuing availability of generating units and their ability to operate at or near full capacity.

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 (including employee workforce initiatives).

The ability to improve electric commodity margins and the impact of, among other factors, the increased cost of coal and coal transportation on such margins and the ability to experience growth in the distribution business.

The changing market conditions that could affect the value of assets held in the registrants nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy to make additional contributions sooner, or in amounts that are larger than currently anticipated.

The ability to access the public securities and other capital and credit markets in accordance with FirstEnergy s financing plan and the cost of such capital.

Changes in general economic conditions affecting the registrants.

The state of the capital and credit markets affecting the registrants.

Interest rates and any actions taken by credit rating agencies that could negatively affect the registrants access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.

The continuing uncertainty of the national and regional economy and its impact on the registrants major industrial and commercial customers.

Issues concerning the soundness of financial institutions and counterparties with which the registrants do business.

The expected timing and likelihood of completion of the proposed merger with Allegheny, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management s time and attention from FirstEnergy s ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.

The risks and other factors discussed from time to time in the registrants SEC filings, and other similar factors.

Dividends declared from time to time on FirstEnergy s common stock during any annual period may in aggregate vary from the indicated amount due to circumstances considered by FirstEnergy s Board of Directors at the time of the actual declarations. 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 the registrants 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 any forward-looking statements contained herein as a result of new information, future events or otherwise.

FIRSTENERGY CORP.
MANAGEMENT S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Earnings available to FirstEnergy Corp. in 2010 were $784 million, or basic earnings of $2.58 per share of common stock ($2.57 diluted), compared with $1.01 billion, or basic earnings of $3.31 per share of common stock ($3.29 diluted), in 2009 and $1.34 billion, or basic earnings of $4.41 per share ($4.38 diluted), in 2008.

Change in Basic Earnings Per Share From Prior Year	2010	2009
Basic Earnings Per Share Prior Year	$ 3.31	$ 4.41
Non-core asset sales/impairments	(0.37)	0.47
Generating plant impairments	(0.77)	
Litigation settlement	0.04	(0.03)
Trust securities impairments	0.03	0.16
Regulatory charges	0.45	(0.55)
Derivative mark-to-market adjustment	0.35	(0.42)
Organizational restructuring	0.14	(0.14)
Debt redemption premium	0.32	(0.31)
Merger transaction costs 2010	(0.16)	
Income tax resolution	(0.57)	0.68
Revenues	1.06	(1.85)
Fuel and purchased power	(0.68)	(0.09)
Amortization of regulatory assets, net	0.22	(0.02)
Investment income	(0.20)	0.20
Interest expense		(0.14)
Transmission expense	(0.20)	0.73
Other expenses	(0.39)	0.21
Basic Earnings Per Share	$ 2.58	$ 3.31

2010 was a transformational year for FirstEnergy, and one in which we built a strong foundation for future success.

On February 11, 2010, FirstEnergy and Allegheny announced a proposed merger that would create the nation s largest electric utility system, with:

- more than 6 million customers across ten regulated electric distribution subsidiaries in Ohio, Pennsylvania, New Jersey, Maryland and West Virginia,
- generation subsidiaries owning or controlling approximately 24,000 MWs of generating capacity from a diversified mix of coal, nuclear, natural gas, oil and renewable power, and
- transmission subsidiaries owning over 20,000 miles of high-voltage lines connecting the Midwest and Mid-Atlantic.

Pursuant to the terms of the merger, Allegheny shareholders would receive 0.667 of a share of FirstEnergy common stock in exchange for each share of Allegheny they own.

2010 also marked FirstEnergy s final transition year to competitive markets with the expiration of the rate cap on Met-Ed and Penelec s retail generation rates on December 31, 2010. Beginning in 2011, Met-Ed and Penelec obtain their power supply from the competitive wholesale market and fully recover their generation costs through retail rates. All of FirstEnergy s other regulated utilities previously transitioned to competitive generation markets.

The effects of the uncertainty in the U.S. economy continue to present challenges. Although economic recovery began across our service territories, power sales and deliveries have still not returned to pre-recessionary levels. Distribution deliveries in 2010 were 108.0 million MWH, compared with 102.3 million MWH in 2009, driven primarily by an

8.4% increase in deliveries to the industrial sector, with the largest gains from customers in the automotive and steel industries. Industrial usage is lagging pre-recessionary levels by approximately 11%. Residential sales were up 6%, primarily due to warmer weather during the summer of 2010. Wholesale power prices continued to be weak; however, generation output improved in 2010 with output of 74.9 million MWH compared to the 2009 output of 65.6 million MWH.

In the second half of 2010, FES entered into financial transactions that offset the mark-to-market impact of 500 MW of legacy purchased power contracts which were entered into in 2008 for delivery in 2010 and 2011 and which were marked to market beginning in December 2009. These financial transactions eliminate the volatility in GAAP earnings associated with marking these contracts to market through the end of 2011.

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FES continued implementation of its retail strategy by focusing on direct, governmental aggregation and POLR sales opportunities. As of February 8, 2011, FES committed sales (as a percentage of total projected sales) for 2011 and 2012 were 96% and 65% respectively.

Operational Matters

PJM RTO Integration

In March 2010 two FRR Integration Auctions were conducted by PJM on behalf of the Ohio Companies to secure electric capacity for delivery years June 1, 2011, through May 31, 2012, and June 1, 2012, through May 31, 2013. In the 2011/2012 auction, 27 suppliers participated and 12,583 MW of unforced capacity (the MW bid into the auction after adjusting for historical forced outage rates) cleared at a price of $108.89/MW-day. The 2012/2013 auction had 28 market participants, with 13,038 MW of unforced capacity clearing at a price of $20.46/MW-day. FirstEnergy plans to integrate its operations into PJM by June 1, 2011.

Nuclear Generation

On February 28, 2010, the Davis-Besse Nuclear Plant (908 MW) shut down for its 16th scheduled refueling outage to exchange 76 of 177 fuel assemblies and to conduct numerous safety inspections. During the outage, it was determined through testing that modification work also needed to be performed on certain CRDM nozzles that penetrate the reactor vessel head. Modifications of 24 of the 69 nozzles on the reactor head were completed and Davis-Besse returned to service on June 29, 2010. The plant was originally scheduled to have a new reactor vessel head installed in 2014. This timeline was voluntarily accelerated, and FirstEnergy plans to install the new reactor head in the fall of 2011.

On August 30, 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license. In a letter dated October 18, 2010, the NRC determined that the Davis-Besse license renewal application was complete and acceptable for docketing and further review. Davis-Besse currently is licensed until 2017; if approved, the renewal would extend operations for an additional 20 years, until 2037.

On October 2, 2010, Beaver Valley Nuclear Power Station Unit 1 (911 MW) began its scheduled refueling and maintenance outage. During the outage FENOC exchanged 60 of the 157 fuel assemblies, conducted safety inspections and performed routine maintenance work. The plant returned to service on November 4, 2010.

Coal and Gas Fired Generation

On March 31, 2010, FGCO closed the sale of its 340 MW Sumpter Plant in Sumpter, Michigan, to Wolverine Power Supply Cooperative, Inc. FirstEnergy recorded a $6 million impairment of the Sumpter plant in December 2009 and a loss of $9 million with the sale in the first quarter of 2010. The plant consists of four 85 MW natural gas turbines and represented FirstEnergy s only generation assets in Michigan.

On August 12, 2010, FirstEnergy announced that operational changes would be made to some of the smaller coal-fired units in response to the slow economy, the lower demand for electricity and uncertainty related to proposed new federal environmental regulations. Beginning September 2010, Bay Shore units 2-4, Eastlake units 1-4, the Lake Shore Plant, and the Ashtabula Plant, which total 1,620 MW of capacity, began operating with minimum three-day notice and in response to consumer demand. FGCO recognized an impairment of $303 million ($190 million after tax) related to these assets in 2010.

On November 17, 2010, we announced plans to cancel repowering Units 4 and 5 (312 MW) at the R.E. Burger Plant to generate electricity principally with biomass. FGCO recognized an impairment of $72 million ($45 million after tax) and permanently shut down these units on December 31, 2010, due to the current market conditions.

During the third quarter of 2010, FGCO re-evaluated the schedule for completing the Fremont Plant (707 MW) due to market conditions and the extension of the tax incentives included in the Small Business legislation through 2011. As a result, FGCO extended the plant s expected completion to December 31, 2011, to reduce overtime labor cost and outside contractor spend for the remainder of the project. On February 3, 2011, FirstEnergy and American Municipal Power, Inc., entered into a non-binding Memorandum of Understanding (MOU) for the sale of our Fremont Energy Center. The MOU provides, among other things, for the parties to engage in exclusive negotiations towards a definitive agreement expected to be executed in March, 2011, with a targeted closing date in July, 2011.

On December 28, 2010, FirstEnergy closed the sale of 6.65% of FGCO s participation interest in the output of OVEC (approximately 150 MW) to Peninsula Generation Cooperative, a subsidiary of Wolverine Power Supply Cooperative, Inc., effective December 31, 2010. FirstEnergy s remaining interest in OVEC is 4.85%. The gain from this transaction increased 2010 net income by $53.8 million.

The Signal Peak coal mining operation in Montana, a joint venture owned 50% by FirstEnergy, began production in December 2009, providing FirstEnergy flexibility with respect to coal commodity supply for its fossil generation fleet. As part of this transaction, we also entered into a 15-year agreement to purchase up to 10 million tons of coal annually from the mine, securing a long-term western fuel supply at attractive prices. Signal Peak provides us with optionality to either burn its western coal in our units, or sell the coal through the venture to other domestic or international buyers.

Finally, in 2010 we completed a $1.8 billion environmental retrofit of the W.H. Sammis Plant in Stratton, Ohio. This project was designed to reduce SO_2 emissions by 95% at the plant and NOx emissions by 90% at its two largest units. This project was among the largest AQC retrofits ever completed in the United States.

Ohio Wind Power Project

On February 8, 2011, FES announced its agreement to purchase 100 MW of output from Blue Creek Wind Farm (304 MW), which is being built in western Ohio by Iberdrola Renewables. Under terms of the agreement FES will purchase 100 MW of the total output of the project for 20 years beginning in October 2012.

Financial Matters

Cash flow from operations in 2010 was at a record level of $3.1 billion. During the year we also completed refinancing $725 million of variable rate debt to fixed rate debt.

In April and June of 2010, FGCO, a subsidiary of FES, purchased $235 million of variable rate PCRBs and $15 million of fixed rate PCRBs, respectively, originally issued on its behalf. In August of 2010, FES completed the remarketing of the $250 million of PCRBs; $235 million were successfully converted from a variable interest rate to a fixed interest rate and the remaining $15 million of PCRBs remain in a fixed rate mode. The $235 million series now bears a per-annum rate of 2.25% and is subject to mandatory purchase on June 3, 2013. The $15 million series now bears a per-annum rate of 1.5% and is subject to mandatory purchase on June 1, 2011.

Subsequently, in October of 2010, FES completed the refinancing and remarketing of six series of PCRBs totaling $313 million. These series were converted from a variable interest rate to a fixed interest rate of 3.375% per-annum and are subject to mandatory purchase on July 1, 2015. On December 3, 2010, FES and Penelec completed the refinancing and remarketing of five series of PCRBs totaling $178 million. These series were converted from variable rate to fixed interest rates ranging from 2.25% to 3.75% per-annum and are subject to mandatory purchase.

In May of 2010, FirstEnergy terminated fixed-for-floating interest rate swap agreements with a notional value of $3.2 billion, which resulted in cash proceeds of $43.1 million. As of June 30, 2010, the debt underlying the $3.2 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 6%, which the swaps converted to a current weighted average variable rate of 4%. On July 16, 2010, FirstEnergy terminated these fixed-for-floating interest rate swap agreements resulting in cash proceeds of $83.6 million. The related gain from both of those transactions will generally be amortized to earnings over the life of the underlying debt. As of December 31, 2010, there were no fixed-to-floating swaps hedging the consolidated interest rate risk associated with FirstEnergy s consolidated debt.

On June 1, 2010, Penn redeemed $1 million of 5.40% PCRBs, due 2013, and on July 30, 2010, redeemed $6.5 million of its 7.65% FMBs due in 2023.

On October 22, 2010, Signal Peak Energy and Global Rail Group, as borrowers, entered into a new $350 million senior secured term loan facility. The two-year syndicated bank loan is guaranteed by FirstEnergy and the other owners of the borrowers. The proceeds from the loan were used to repay bank borrowings ($63 million) and debt owed to FirstEnergy ($258 million) with the balance to be used for other general corporate purposes.

In February 2010, S&P issued a report lowering FirstEnergy s and its subsidiaries credit ratings by one notch, while maintaining its stable outlook. Moody s and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries. These rating agency actions were taken in response to the announcement of the proposed merger with Allegheny. On September 28, 2010 S&P affirmed the ratings and stable outlook of FE and its subsidiaries. On December 15, 2010, Fitch revised its outlook on FirstEnergy and FES from stable to negative and affirmed the rating for FirstEnergy and its subsidiaries.

Regulatory Matters

Ohio ESP

The Ohio Companies will be operating under a new ESP effective June 1, 2011 through May 31, 2014, which was filed in March 2010 and approved by the PUCO in August 2010. That ESP provides customers with no overall increase to base distribution rates during the plan period and limits the costs they will pay related to certain PJM transmission projects. The ESP provides the Ohio Companies with recovery of capital invested in their distribution businesses through a Delivery Capital Recovery Rider effective January 1, 2012, through May 31, 2014. Generation rates for the annual delivery periods during the plan are determined through a CBP which will be conducted every

October and January for generation service through May 31, 2014. The first two CBPs were conducted in October 2010 and January 2011. Both auctions consisted of one, two and three-year products. The results of these auctions were accepted by the PUCO. The next auction is scheduled for October 2011.

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Pennsylvania Default Service Plan

On October 20, 2010, the PPUC approved the results of various auctions held to procure the default service requirements for Met-Ed and Penelec customers who choose not to shop with an alternative supplier. The auction was the last of four auctions for the five-month period of January 1, 2011 to May 31, 2011, and the second of four auctions to procure commercial default service requirements for the 12-month period of June 1, 2011 to May 31, 2012 and residential requirements for the 24-month period of June 1, 2011 to May 31, 2013. The PPUC also approved the default service RFP for the Residential Fixed Block On-Peak and Off-Peak energy products. On January 18-20, 2011, Met-Ed, Penelec and Penn conducted auctions to procure a portion of the default service requirements for their customers who choose not to shop with an alternative supplier. The January 2011 auction was the third of four auctions for Met-Ed and Penelec and the first of two auctions for Penn to procure commercial default service requirements for the 12-month period of June 1, 2011 to May 31, 2012 and residential requirements for the 24-month period of June 1, 2011 to May 31, 2013. For Met-Ed, Penelec and Penn commercial customers the tranche-weighted average price ($/MWH) was $69.97, $59.32 and $57.88, respectively, and for residential customers the tranche-weighted average price was $70.69, $59.74 and $55.39, respectively. This was also the first of two auctions held to procure residential service requirements for the 12-month period of June 1, 2011 to May 31, 2012. For Met-Ed, Penelec and Penn residential customers the tranche-weighted average price ($/MWH) was $67.43, $58.01 and $60.29, respectively. In addition, the January 2011 auction procured supply for Met-Ed and Penelec industrial customers Hourly Priced Default Service. For Met-Ed and Penelec, the average 12-month price ($/MWH) was $9.90 and $9.91, respectively. The PPUC approved the results of the January 2011 auctions on January 24, 2011.

Penn Power s settlement for approval of its Default Service Plan for the period of June 1, 2011 through May 31, 2013 was approved by the PPUC on October 21, 2010. Although the PPUC s Order approving the Joint Petition held that the provisions relating to the recovery of MISO exit fees and one-time PJM integration costs (resulting from Penn's June 1, 2011 exit from MISO and integration into PJM) were approved, it made such provisions subject to the approval of cost recovery by FERC. Therefore, Penn may not put these provisions into effect until FERC has approved the recovery and allocation of MISO exit fees and PJM integration costs.

Energy Efficiency, Smart Grid and Smart Meter Programs

On June 3, 2010, FirstEnergy and the DOE signed grants totaling $57.4 million that were awarded as part of the American Recovery and Reinvestment Act to introduce smart grid technologies in targeted areas in Pennsylvania, Ohio, and New Jersey. The DOE grants represent 50% of the funding for approximately $115 million FirstEnergy plans to invest in smart grid technologies. The PPUC, PUCO and NJBPU have approved recovery of the remaining costs not funded through the DOE grant for the smart grid programs in Pennsylvania, Ohio and New Jersey, respectively, and the programs are underway in all three states.

Pennsylvania s Act 129 (Act 129) requires all Pennsylvania electric distribution companies with more than 100,000 customers to install smart meter technology within 15 years. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision issued on January 28, 2010 and decided various issues regarding the SMIP for the Pennsylvania Companies. An order consistent with Chairman Cawley s Motion was entered on June 9, 2010. The companies filed a petition for reconsideration on a single portion of the order, and on August 5, 2010, the PPUC entered an order granting in part the petition for reconsideration. The Pennsylvania Companies SMIP will assess the technologies, vendors, capital cost, and potential benefits of smart meter technology during an assessment period that covers the next 24 months. The Pennsylvania Companies expect to incur approximately $29.5 million of costs during the assessment period which they expect to recover through the Smart Meter Technologies Charge rider. At the end of the assessment period, the Pennsylvania Companies will submit to the PPUC a deployment plan for the full scale deployment of smart meters. The costs to implement the SMIP could be material. However, assuming these costs satisfy a just and reasonable standard they are expected to be recovered in a rider (Smart Meter Technologies Charge Rider) which was approved when the PPUC approved the SMIP.

Act 129 also requires utilities to reduce energy consumption and peak demand, with electricity consumption reduction targets of 1% by May 31, 2011, and 3% by May 31, 2013, and a peak demand reduction target of 4.5% by May 31, 2013. The Pennsylvania Companies responded by offering a wide variety of programs to residential, commercial, industrial, governmental and non-profit customers through their PPUC-approved EE&C Plans.

JCP&L Rate Adjustment

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2010, the accumulated deferred cost balance was a credit of approximately $37 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. On February 10, 2011, the NJBPU approved a stipulation which allows the change in rates to become effective March 1, 2011.

On January 18, 2011, JCP&L provided information to the NJBPU regarding the proposed merger between FirstEnergy and Allegheny. A stipulation between JCP&L, Board Staff and Rate Counsel was also provided. The Board reviewed the Stipulation at its January 25, 2011 meeting and issued an Order on February 10, 2011 indicating that it did not object to the transaction proceeding.

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FIRSTENERGY S BUSINESS

We are a diversified energy company headquartered in Akron, Ohio, that operates primarily through two core business segments (see Results of Operations).

Energy Delivery Services transmits and distributes electricity through our seven utility distribution companies and ATSI, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. This segment also purchases power for its POLR and default service requirements in all three states. Its revenues are primarily derived from the delivery of electricity within our service areas and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

The service areas of our utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,037,000
Penn	Western Pennsylvania	160,000
CEI	Northeastern Ohio	751,000
TE	Northwestern Ohio	310,000
JCP&L	Northern, Western and East Central New Jersey	1,098,000
Met-Ed	Eastern Pennsylvania	553,000
Penelec	Western Pennsylvania	591,000
ATSI	Service areas of OE, Penn, CEI and TE	

Competitive Energy Services segment supplies electric power to end-use customers through retail and wholesale arrangements primarily in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. This business segment controls 13,236 MWs of capacity and also purchases electricity to meet sales obligations. The segment s net income is primarily derived from affiliated and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment s customers.

STRATEGY AND OUTLOOK

FirstEnergy s vision is to be a leading regional energy provider, recognized for operational excellence, outstanding customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of our employees.

Our near-term focus is on getting the merger closed and then successfully managing the merger integration process and capturing long-term value to benefit our customers, shareholders and employees.

The merger integration process is underway and is expected to create significant efficiencies and economies of scale as we share best practices across the new organization. Merger integration teams comprised of employees from both FirstEnergy and Allegheny began working in April 2010 to identify value drivers and estimate transaction benefits.

The proposed merger is a natural geographic fit that would bring together complementary assets and corporate cultures and create a strong company that is well-positioned for growth. Our strength is the diversity of our assets, and our strategic focus is on creating long-term value through our core operations distribution operations, transmission operations and competitive generation and retail operations.

In our distribution operations, we remain focused on reliability, customer service and safety, and maintaining stable earnings growth. Our combined company will be committed to meeting regulatory expectations and leveraging best practices across seven states and ten operating utilities. FirstEnergy s management structure and philosophy supports local authority and decision-making by maintaining a local presence, which includes regional offices for our utility operations.

Presently, our competitive generation portfolio of 13,236 MW contains a diverse mix of quality assets, including nuclear, coal, natural gas, wind and pumped storage.

In response to reduced customer demand and uncertainty related to proposed new federal environmental regulations, FirstEnergy announced in August 2010 operational changes at several fossil plants. Affected are nine units at four plants located on the shore of Lake Erie in Ohio, with 1,620 MW of total capacity. In September 2010, the units began operating with a minimum three-day notice and in response to customer demand. These operational changes provide future flexibility regarding potential plant retirements given the current ongoing uncertainty regarding future EPA mandates or environmental legislation. (see Environmental Outlook below). We plan to make a similar evaluation of Allegheny s fossil assets once the merger is completed; however, because most of Allegheny s supercritical units have already been retrofitted with environmental control equipment, it is the bulk of their older, regulated subcritical units that are most exposed to potential regulations.

In the fall of 2011, we plan to replace Davis-Besse s reactor vessel head, accelerating the original replacement scheduled in 2014. We expect this proactive approach to provide additional margins of safety and reliability.

Construction continues on our Fremont Energy Center, which includes two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. We expect to complete construction of this facility by the end of 2011. On February 3, 2011, FirstEnergy and American Municipal Power, Inc. (AMP), entered into a non-binding Memorandum of Understanding (MOU) for the sale of our Fremont Energy Center. The MOU provides, among other things, for the parties to engage in exclusive negotiations towards a definitive agreement expected to be executed in March, 2011, with a targeted closing date in July, 2011. In addition to Fremont, Signal Peak has been identified as a non-strategic asset that could be made available for sale.

FirstEnergy has identified potential post-merger benefits in the competitive generation and retail business mostly related to expanding the FirstEnergy operating philosophy and model to the combined operation. These include:

- Economies of scale and best practices related to fuel procurement and transportation;
- Expanded use of fuel blending techniques;
- Generation asset reliability improvement;
- Dispatch optimization;
- Outage best practices; and
- Expansion of the retail sales growth strategy.

Our strategy is to sell our own physical generation output to sales channels in close proximity to our fleet at the highest achievable margins. Our retail business remains a key component of our strategy. FES continues to expand its regional reach through retail sales by using its competitive generation assets to back POLR, governmental aggregation and direct sales commitments.

Wholesale power prices remain under pressure in response to continued low gas prices, but we expect future improvements in power prices to benefit the combined fleet.

Financial Outlook

We remain committed to managing our operating and capital costs in order to achieve our financial goals and commitment to shareholders.

Our liquidity position remains strong, with access to more than $3.2 billion of liquidity, of which approximately $3.1 billion was available as of January 31, 2011.

Capital expenditures in 2011 are projected to be $1.4 billion, compared to $1.8 billion in 2010. We intend to continue to fund our capital requirements through cash generated from operations**.**

Positive earnings drivers for 2011 are expected to include:

- Increased retail revenues associated with FES POLR, governmental aggregation and direct sales;
- Reduced fuel expenses; and
- Increased margin from Signal Peak.

Negative earnings drivers for 2011 are expected to include:

- Decreased revenues associated with the expiration of the Met Ed/Penelec partial requirements agreement with FES;
- Increase in net ancillary, congestion, and capacity expenses;
- Increased purchased power expenses;
- Additional planned nuclear outage for Davis-Besse s reactor head replacement; and
- Increased depreciation expenses and reduced capitalized interest, primarily associated with the Sammis plant environmental project.

Distribution deliveries and non-fuel, non-outage O&M expenses including employee benefits are expected to be essentially flat in 2011 compared to 2010.

FirstEnergy s $2.75 billion revolving credit facility matures in August 2012. We intend to review our revolving credit facility needs post-merger and at a minimum anticipate pursuing renewal of the existing facility during the first half of 2011.

In December 2010, a new federal income tax law became effective that provides for bonus depreciation tax benefits. This new law is expected to provide approximately $500 million in additional cash to FirstEnergy through 2012.

We remain focused on liquidity and a strong balance sheet, as well as maintaining investment grade credit ratings. Our financial plan accelerates our goal of improving our financial strength and flexibility by significantly reducing debt by the end of 2012. In addition to cash generated from operations, we expect to deploy cash received through bonus depreciation tax benefits, as well as cash from the future sale of certain non-core assets, to this debt reduction initiative. These actions are expected to improve our credit metrics over the next several years.

Capital Expenditures Outlook

Our capital expenditure forecast for 2011 is projected to be $1.4 billion, which represents a $393 million decrease from 2010.

The main drivers of this decrease are the 2010 completion of the $1.8 billion Sammis AQC environmental compliance project and reduced spending for the Fremont facility, scheduled for completion in 2011.

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Capital expenditures for our competitive energy services business (excluding the AQC project and Fremont facility) are expected to increase slightly in 2011. The primary cause is the previously announced decision to accelerate the replacement of the Davis-Besse nuclear reactor vessel head. This initiative began in 2010 and is expected to be completed in 2011. Other planned generation investments provide for maintenance of critical generation assets, deliver operational improvements to enhance reliability, and support our generation to market strategy.

For our regulated operations, capital expenditures are forecasted at $730 million in 2011. Approximately $100 million has been allocated to the transmission expansion initiative, which includes projects to satisfy transmission capacity and reliability requirements, transitioning to the PJM market, and connecting new load delivery and new wholesale generation points. Expenditures for Ohio and Pennsylvania energy efficiency and advanced metering initiatives are expected to be primarily reimbursed from distribution customers and federal stimulus funding. Other investments for transmission and distribution infrastructure are designed to achieve cost-effective improvements in the reliability of our service.

For 2012 and 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion, exclusive of any additional opportunities or future mandated spending. Planned capital initiatives promote reliability, improve operations, and support current environmental and energy efficiency directives.

Actual capital spending for 2010 and projected capital spending for 2011 are as follows:

Capital Spending by Business Unit	**2010**	**2011**
	(In millions)	
Energy Delivery	$ 729	$ 630
Nuclear	324	320
Fossil	174	160
FES Other	21	10
Corporate	59	50
AQC	249	4
Baseline Capital Expenditures	$ 1,556	$ 1,174
Fremont Facility	148	56
Burger Biomass	7	
Transmission Expansion	79	100
Davis-Besse Reactor Vessel Head Replacement	23	90
	$ 1,813	$ 1,420

Environmental Outlook

At FirstEnergy, we continually strive to enhance environmental protection and remain good stewards of our natural resources. We devote significant resources to environmental compliance efforts, and our employees share a commitment to, and accountability for, environmental performance. Our corporate focus on continuous improvement is integral to our environmental programs.

We have spent more than $7 billion on environmental protection efforts since the initial passage of the Clean Air and Water Acts in the 1970s, and these investments are making a difference. Over the past five years, we have invested approximately $1.8 billion at our W.H. Sammis Plant in Stratton, Ohio, to further reduce emissions of SO_2 by over 95% and NOx by at least 64%. This is one of the largest environmental retrofit projects in the nation and was recognized by Platts as the 2010 construction project of the year. Since 1990, we have reduced emissions of NOx by more than 83%, SO_2 by more than 82%, and mercury by about 60%. Also, our CO_2 emission rate, in pounds of CO_2 per kWh, has dropped by 19% during this period. Emission rates for our power plants are lower than the regional average.

By the end of 2011, we expect approximately 70% of our generation fleet to be non-emitting or low emitting generation. Over 52% of our coal-fired generating fleet will have full NOx and SO_2 equipment controls thus significantly decreasing our exposure to future environmental requirements.

One of the key issues facing our company and industry is global-climate change-related mandates. Lawmakers at the state and federal levels are exploring and implementing a wide range of responses. We believe our generation fleet is very well positioned to compete in a carbon-constrained economy. In addition, we believe that upon consummation of the proposed merger with Allegheny, our competitive position will be enhanced with an even more diverse mix of fully-scrubbed fossil generation, non-emitting nuclear and renewable generation, including large-scale storage.

We have taken aggressive steps over the past two decades that have increased our generating capacity without adding to overall CO_2 emissions. For example, since 1990, we have reconfigured our fleet by retiring nearly 1,000 MWs of older, coal-based generation and adding more than 1,800 MWs of non-emitting nuclear capacity. Through these and other actions, we have increased our generating capacity by nearly 15% over the same period while avoiding some 350 million metric tons of CO_2 emissions. Today, nearly 40% of our electricity is generated without emitting CO_2 a key advantage that will help us meet the challenge of future governmental climate change mandates. And with recent announcements in 2009, including the expanded use of renewable energy, energy storage and natural gas, our CO_2 emission rate will decline even further in the future.

We have taken a leadership role in pursuing new ventures and testing and developing new technologies that show promise in achieving additional reductions in CO_2 emissions. These include:

- Sales of over 1 million MWH per year of wind generation.
- Testing of CO_2 sequestration to gain a better understanding of the potential for geological storage of CO_2.
- Supporting afforestation growing forests on non-forested land and other efforts designed to remove CO_2 from the environment.
- Reducing emissions of SF_6 (sulfur hexafluoride) by nearly 15 metric tons, resulting in an equivalent reduction of nearly 315,000 metric tons of CO_2, through the EPA s SF6 Emissions Reduction Partnership for Electric Power Systems.
- Supporting research to develop and evaluate cost effective sorbent materials for CO_2 capture including work by Powerspan at the Burger Plant, The University of Akron and the EPRI.

We remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with global climate change, hazardous air pollutants, coal combustion residues and water effluent discharges. We are committed to working with policy makers and regulators to develop fair and reasonable requirements, with the goal of reducing emissions while minimizing the economic impact on our customers. Due to the significant uncertainty as to the final form or timing of any such legislation and regulation at both the federal and state levels, we are unable to determine the potential impact and risks associated with future emissions requirements.

We also have a long history of supporting research in distributed energy resources. Distributed energy resources include fuel cells, solar and wind systems or energy storage technologies located close to the customer or direct control of customer loads to provide alternatives or enhancements to the traditional electric power system. We are testing the world s largest utility-scale fuel cell system at our Eastlake power plant to determine its feasibility for augmenting generating capacity during summer peak-use periods. Through a partnership with EPRI, the Cuyahoga Valley National Park, the Department of Defense and Case Western Reserve University, two solid-oxide fuel cells were installed as part of a test program to explore the technology and the environmental benefits of distributed generation.

We are also evaluating the impact of distributed energy storage on the distribution system through analysis and field demonstrations of advanced battery technologies. FirstEnergy s EasyGreen® load-management program utilizes two-way communication capability with customers non-critical equipment such as air conditioners in New Jersey and Pennsylvania to help manage peak loading on the electric distribution system. FirstEnergy has also made an online interactive energy efficiency tool, Home Energy Analyzer, available for its customers to help achieve electricity use-reduction goals.

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RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges, including:

- risks arising from the reliability of our power plants and transmission and distribution equipment;
- changes in commodity prices could adversely affect our profit margins;
- we are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- the use of derivative contracts by us to mitigate risks could result in financial losses that may negatively impact our financial results;
- financial derivatives reforms could increase our liquidity needs and collateral costs;
- our risk management policies relating to energy and fuel prices, and counterparty credit, are by their very nature risk related, and we could suffer economic losses despite such policies;
- nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- capital market performance and other changes may decrease the value of the decommissioning trust fund, pension fund assets and other trust funds which then could require significant additional funding;
- we could be subject to higher costs and/or penalties related to mandatory reliability standards set by NERC/FERC or changes in the rules of organized markets and the states in which we do business;
- we rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted, including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;
- disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities and impact financial results;
- temperature variations as well as weather conditions or other natural disasters could have a negative impact on our results of operations and demand significantly below or above our forecasts could adversely affect our energy margins;
- we are subject to financial performance risks related to regional and general economic cycles and also related to heavy manufacturing industries such as automotive and steel;
- increases in customer electric rates and economic uncertainty may lead to a greater amount of uncollectible customer accounts;
- the goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;
- we face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- significant increases in our operation and maintenance expenses, including our health care and pension costs, could adversely affect our future earnings and liquidity;
- our business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or results of operations;
- acts of war or terrorism could negatively impact our business;
- capital improvements and construction projects may not be completed within forecasted budget, schedule or scope parameters;
- changes in technology may significantly affect our generation business by making our generating facilities less competitive;

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we may acquire assets that could present unanticipated issues for our business in the future, which could adversely affect our ability to realize anticipated benefits of those acquisitions;
ability of certain FirstEnergy companies to meet their obligations to other FirstEnergy companies;
our pending merger with Allegheny may not achieve its intended results;
upon consummation of the pending merger we will be subject to business uncertainties that could adversely affect our financial results;

once the pending merger is closed the combined company will have a higher percentage of coal-fired generation capacity compared to FirstEnergy s previous generation mix. As a result, FirstEnergy may be exposed to greater risk from regulations of coal and coal combustion by-products than it faced prior to the merger;
complex and changing government regulations could have a negative impact on our results of operations;
regulatory changes in the electric industry, including a reversal, discontinuance or delay of the present trend toward competitive markets, could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
the prospect of rising rates could prompt legislative or regulatory action to restrict or control such rate increases; this in turn could create uncertainty affecting planning, costs and results of operations and may adversely affect the utilities ability to recover their costs, maintain adequate liquidity and address capital requirements;
our profitability is impacted by our affiliated companies continued authorization to sell power at market-based rates;
there are uncertainties relating to our participation in RTOs;
a significant delay in or challenges to various elements of ATSI s consolidation into PJM, including but not limited to, the intervention of parties to the regulatory proceedings could have a negative impact on our results of operations and financial condition;
energy conservation and energy price increases could negatively impact our financial results;
our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements;
the EPA is conducting NSR investigations at a number of our generating plants, the results of which could negatively impact our results of operations and financial condition;
costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws, including limitations on GHG emissions could adversely affect cash flow and profitability;
the physical risks associated with climate change may impact our results of operations and cash flows;
remediation of environmental contamination at current or formerly owned facilities;
availability and cost of emission credits could materially impact our costs of operations;
mandatory renewable portfolio requirements could negatively affect our costs;
we are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;
the continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
future changes in financial accounting standards may affect our reported financial results;

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increases in taxes and fees;
interest rates and/or a credit rating downgrade could negatively affect our financing costs, our ability to access capital and our requirement to post collateral;
we must rely on cash from our subsidiaries and any restrictions on our utility subsidiaries ability to pay dividends or make cash payments to us may adversely affect our financial condition;
we cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid;

disruptions in the capital and credit markets may adversely affect our business, including the availability and cost of short-term funds for liquidity requirements, our ability to meet long-term commitments, our ability to hedge effectively our generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect our results of operations, cash flows and financial condition; and
questions regarding the soundness of financial institutions or counterparties could adversely affect us.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy s business segments. A reconciliation of segment financial results is provided in Note 15 to the consolidated financial statements. Earnings available to FirstEnergy by major business segment were as follows:

							Increase (Decrease)			
		2010		**2009**		**2008**		**2010 vs 2009**		**2009 vs 2008**
				(In millions, except per share data)						
Earnings (Loss) By Business Segment:										
Energy delivery services	$	607	$	435	$	916	$	172	$	(481)
Competitive energy services		258		517		472		(259)		45
Other and reconciling adjustments*		(81)		54		(46)		(135)		100
Total	$	784	$	1,006	$	1,342	$	(222)	$	(336)
Basic Earnings Per Share	$	2.58	$	3.31	$	4.41	$	(0.73)	$	(1.10)
Diluted Earnings Per Share	$	2.57	$	3.29	$	4.38	$	(0.72)	$	(1.09)

* Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses, noncontrolling interests and the elimination of intersegment transactions.

Summary of Results of Operations 2010 Compared with 2009

Financial results for FirstEnergy s major business segments in 2010 and 2009 were as follows:

2010 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 9,271	$ 3,252	$	$ 12,523
Other	542	292	(92)	742
Internal*	139	2,301	(2,366)	74
Total Revenues	9,952	5,845	(2,458)	13,339
Expenses:				
Fuel		1,440	(8)	1,432
Purchased power	5,266	1,724	(2,366)	4,624
Other operating expenses	1,492	1,436	(78)	2,850
Provision for depreciation	451	254	41	746
Amortization of regulatory assets	722			722
Deferral of new regulatory assets				
Impairment of long lived assets		384		384
General taxes	653	113	10	776
Total Expenses	8,584	5,351	(2,401)	11,534
Operating Income	1,368	494	(57)	1,805
Other Income (Expense):				
Investment income	102	51	(36)	117
Interest expense	(496)	(221)	(128)	(845)
Capitalized interest	5	92	68	165
Total Other Expense	(389)	(78)	(96)	(563)
Income Before Income Taxes	979	416	(153)	1,242
Income taxes	372	158	(48)	482
Net Income (Loss)	607	258	(105)	760
Loss attributable to noncontrolling interest			(24)	(24)
Earnings available to FirstEnergy Corp.	$ 607	$ 258	$ (81)	$ 784

*

Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

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2009 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 10,585	$ 1,447	$	$ 12,032
Other	559	447	(82)	924
Internal*		2,843	(2,826)	17
Total Revenues	11,144	4,737	(2,908)	12,973
Expenses:				
Fuel		1,153		1,153
Purchased power	6,560	996	(2,826)	4,730
Other operating expenses	1,424	1,357	(84)	2,697
Provision for depreciation	445	270	21	736
Amortization of regulatory assets	1,155			1,155
Deferral of new regulatory assets	(136)			(136)
Impairment of long lived assets		6		6
General taxes	641	108	4	753
Total Expenses	10,089	3,890	(2,885)	11,094
Operating Income	1,055	847	(23)	1,879
Other Income (Expense):				
Investment income	139	121	(56)	204
Interest expense	(472)	(166)	(340)	(978)
Capitalized interest	3	60	67	130
Total Other Income (Expense)	(330)	15	(329)	(644)
Income Before Income Taxes	725	862	(352)	1,235
Income taxes	290	345	(390)	245
Net Income	435	517	38	990
Loss attributable to noncontrolling interest			(16)	(16)
Earnings available to FirstEnergy Corp.	$ 435	$ 517	$ 54	$ 1,006

* Under the accounting standard for the effects of certain types of regulation, Internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

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Changes Between 2010 and 2009 Financial Results Increase (Decrease)	**Energy Delivery Services**	**Competitive Energy Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ (1,314)	$ 1,805	$	$ 491
Other	(17)	(155)	(10)	(182)
Internal*	139	(542)	460	57
Total Revenues	(1,192)	1,108	450	366
Expenses:				
Fuel		287	(8)	279
Purchased power	(1,294)	728	460	(106)
Other operating expenses	68	79	6	153
Provision for depreciation	6	(16)	20	10
Amortization of regulatory assets	(433)			(433)
Deferral of new regulatory assets	136			136
Impairment of long lived assets		378		378
General taxes	12	5	6	23
Total Expenses	(1,505)	1,461	484	440
Operating Income	313	(353)	(34)	(74)
Other Income (Expense):				
Investment income	(37)	(70)	20	(87)
Interest expense	(24)	(55)	212	133
Capitalized interest	2	32	1	35
Total Other Expense	(59)	(93)	233	81
Income Before Income Taxes	254	(446)	199	7
Income taxes	82	(187)	342	237
Net Income	172	(259)	(143)	(230)
Loss attributable to noncontrolling interest			(8)	(8)
Earnings available to FirstEnergy Corp.	$ 172	$ (259)	$ (135)	$ (222)

* Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

Energy Delivery Services 2010 Compared to 2009

Net income increased $172 million to $607 million in 2010 compared to $435 million in 2009, primarily due to CEI s $216 million regulatory asset impairment in 2009, partially offset by increases in other operating expenses. Lower generation revenues were offset by lower purchased power expenses.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	**2010**	**2009**	**Increase (Decrease)**
		(In millions)	
Distribution services	$ 3,629	$ 3,419	$ 210
Generation sales:			
Retail	4,456	5,764	(1,308)
Wholesale	841	752	89
Total generation sales	5,297	6,516	(1,219)
Transmission	833	1,028	(195)
Other	193	181	12
Total Revenues	$ 9,952	$ 11,144	$ (1,192)

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The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	
Residential	5.9%
Commercial	2.8%
Industrial	8.4%
Total Distribution KWH Deliveries	5.6%

Higher deliveries to residential and commercial customers reflect increased weather-related usage due to a 70% increase in cooling degree days in 2010 compared to 2009, partially offset by a 4% decrease in heating degree days for the same period. In the industrial sector, KWH deliveries increased primarily to major automotive customers (16%), refinery customers (7%) and steel customers (38%). The increase in distribution service revenues also reflects the Pennsylvania Companies recovery of the Pennsylvania EE&C as approved by the PPUC in March 2010 and the accelerated recovery of deferred distribution costs in Ohio, partially offset by a reduction in the transition rate for CEI effective June 1, 2009.

The following table summarizes the price and volume factors contributing to the $1.2 billion decrease in generation revenues in 2010 compared to 2009:

Source of Change in Generation Revenues	**Increase (Decrease)** ***(In millions)***
Retail:	
Effect of 24.9% decrease in sales volumes	$ (1,438)
Change in prices	130
	(1,308)
Wholesale:	
Effect of 8.4% decrease in sales volumes	(64)
Change in prices	153
	89
Net Decrease in Generation Revenues	$ (1,219)

The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies service territories. Total generation KWH provided by alternative suppliers as a percentage of total KWH deliveries by the Ohio Companies increased to 62% in 2010 from 17% in 2009. The decrease in volumes was partially offset by increases in generation revenues due to higher rates from the May 2009 Ohio CBP that include the recovery of transmission costs.

The increase in wholesale generation revenues reflected higher prices and increased capacity sales for Met-Ed and Penelec in the PJM market.

Transmission revenues decreased $195 million primarily due to the termination of the Ohio Companies transmission tariff effective June 1, 2009; transmission costs are now a component of the cost of generation established under the May 2009 Ohio CBP.

Expenses

Total expenses decreased by $1.5 billion due to the following:

Purchased power costs were $1.3 billion lower in 2010, largely due to lower volume requirements. The decrease in volumes from non-affiliates resulted principally from the termination of a third-party supply contract for Met-Ed and Penelec in January 2010 and from the increase in customer shopping in the Ohio Companies service territories. The decrease in purchases from FES also resulted from the increase in customer shopping in Ohio.

An increase in purchased power unit costs from non-affiliates in 2010 resulted from higher capacity prices in the PJM market for Met-Ed and Penelec. A decrease in unit costs for purchases from FES was principally due to the lower weighted average unit price per KWH established under the May 2009 CBP auction for the Ohio Companies effective June 1, 2009.

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Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 619
Change due to decreased volumes	(1,489)
	(870)
Purchases from FES:	
Change due to decreased unit costs	(257)
Change due to decreased volumes	(250)
	(507)
Decrease in costs deferred	83
Net Decrease in Purchased Power Costs	$ (1,294)

Transmission expenses increased $70 million primarily due to higher PJM network transmission expenses and congestion costs for Met-Ed and Penelec, partially offset by lower MISO network transmission expenses that are reflected in the generation rate established under the May 2009 Ohio CBP. Met-Ed and Penelec defer or amortize the difference between revenues from their transmission rider and transmission costs incurred with no material effect on earnings.

Energy efficiency program costs, which are also recovered through rates, increased $41 million in 2010 compared to 2009.

Labor and employee benefit expenses decreased by $34 million due to lower pension and OPEB expenses, lower payroll costs resulting from staffing reductions implemented in 2009, and restructuring expenses recognized in 2009.

Expenses for economic development commitments related to the Ohio Companies ESP were lower by $11 million in 2010 compared to 2009.

Depreciation expense increased $6 million due to property additions since 2009.

Amortization of regulatory assets decreased $433 million due primarily to the absence of the $216 million impairment of CEI s regulatory assets in 2009, reduced net MISO and PJM transmission cost amortization and reduced CTC amortization for Met-Ed and Penelec, partially offset by increased amortization associated with the accelerated recovery of deferred distribution costs in Ohio and a $35 million regulatory asset impairment in 2010 associated with the Ohio Companies ESP.

The deferral of new regulatory assets decreased $136 million in 2010 due to CEI s purchased power cost deferrals that ended in early 2009.

General taxes increased $12 million principally due to a benefit relating to Ohio KWH excise taxes that was recognized in 2009 and applicable to prior years.

Other Expense

Other expense increased $59 million in 2010 compared to 2009 primarily due to lower nuclear decommissioning trust investment income ($37 million) and higher net interest expense associated with debt issuances by the Utilities during 2009 ($22 million).

Competitive Energy Services 2010 Compared to 2009

Net income decreased to $258 million in 2010 compared to $517 million in 2009. The decrease in net income was primarily due to $384 million of impairment charges ($240 million net of tax) in 2010. In addition, FES sold a 6.65%

participation interest in OVEC in 2010 compared to a 9% interest in 2009, accounting for $105 million of the reduction in net income. Investment income from nuclear decommissioning trusts was also lower in 2010. These reductions were partially offset by an increase in sales margins.

Revenues

Total revenues increased $1,108 million in 2010 compared to the same period in 2009 primarily due to an increase in direct and government aggregation sales and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies, other wholesale sales and the reduced OVEC participation interest sale in 2010.

The increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	**2010**	**2009**	**Increase (Decrease)**
		(In millions)	
Direct and Government Aggregation	$ 2,494	$ 779	$ 1,715
POLR	2,436	2,863	(427)
Wholesale	550	632	(82)
Transmission	77	73	4
RECs	74	17	57
Sale of OVEC participation interest	85	252	(167)
Other	129	121	8
Total Revenues	$ 5,845	$ 4,737	$ 1,108

The increase in direct and government aggregation revenues of $1.7 billion resulted from increased revenue from the acquisition of new commercial and industrial customers as well as from new government aggregation contracts with communities in Ohio that provide generation to 1.5 million residential and small commercial customers at the end of 2010 compared to approximately 600,000 customers at the end of 2009. Increases in direct sales were partially offset by lower unit prices. Sales to residential and small commercial customers were also bolstered by summer weather in the delivery area that was significantly warmer than in 2009.

The decrease in POLR revenues of $427 million was due to lower sales volumes and lower unit prices to the Ohio Companies, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 CBP. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract and at prices that were slightly higher than in 2009.

Other wholesale revenues decreased $82 million due to reduced volumes, partially offset by higher prices. Lower sales volumes in MISO were due to available capacity serving increased retail sales in Ohio partially offset by increased sales under bilateral agreements in PJM.

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

Source of Change in Direct and Government Aggregation	**Increase (Decrease)**
	(In millions)
Direct Sales:	
Effect of increase in sales volumes	$ 1,083
Change in prices	(82)
	1,001
Government Aggregation:	
Effect of increase in sales volumes	704
Change in prices	10

		714
Net Increase in Direct and Government Aggregation Revenues	$	1,715

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