FirstEnergy

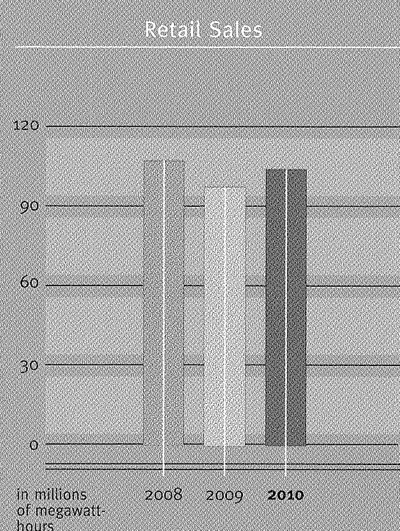
2010 ANNUAL REPORT

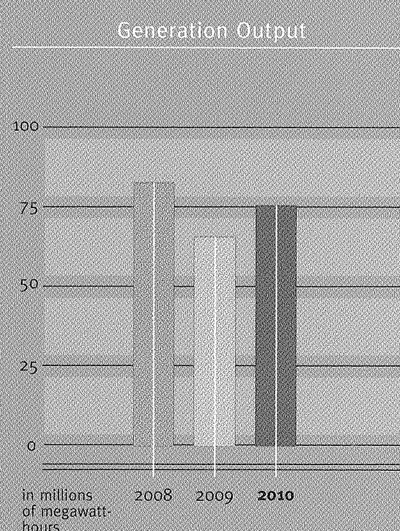
Financial Highlights

Key Accomplishments

- Maintained annual dividend of $2.20 per share
- Generated nearly $3.1 billion in cash from operations
- Completed the transition to fully competitive markets for electricity in Pennsylvania
- Our competitive subsidiary, FirstEnergy Solutions, nearly tripled the number of its retail customers and now serves approximately 1.5 million customers in six states
- Completed the $1.8 billion Air Quality Compliance project at our W.H. Sammis Plant

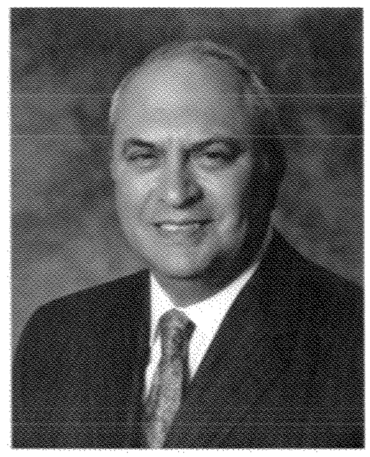
(Dollars in millions, except per share amounts)	**2010**	2009
Total revenues	**$ 13,339**	$ 12,973
Net income	**$ 760**	$ 990
Basic earnings per common share	**$ 2.58**	$ 3.31
Diluted earnings per common share	**$ 2.57**	$ 3.29
Dividends paid per common share	**$ 2.20**	$ 2.20
Book value per common share	**$ 28.03**	$ 28.08
Net cash from operating activities	**$ 3,076**	$ 2,465





Message to Shareholders

We've strengthened our position as an industry leader. The merger of FirstEnergy and Allegheny Energy expands our utility customer base by 35 percent, increases our generating resources by 70 percent, and creates more opportunities to grow our retail generation sales.



Anthony J. Alexander
President and Chief Executive Officer

In addition, with our contiguous service areas and strategically located power plants, we have an ideal platform for creating operating efficiencies and delivering greater value to our shareholders.

Our 10 utilities serve six million customers in six states, making FirstEnergy the largest electric system in the United States based on customers served. And, we control one of the nation's largest, cleanest and most diversified generating fleets – approximately 24,000 megawatts (MW) of capacity including nuclear, coal, natural gas, wind and pumped storage.

The merger more than doubles our highly efficient, supercritical coal capacity, improves the overall environmental performance of our entire fleet, and increases the generation output we have available to sell at market-based prices by almost 40 percent. This larger, more efficient fleet also provides opportunities to grow our business as we expand into new markets with a stronger, more focused competitive operation.

Through this combination, we're creating a premier regional energy provider – stronger, more flexible and better equipped to meet the challenges that lie ahead. And I'm confident our employees will deliver on the promise of the merger by working together to achieve a wide range of operating efficiencies and improvements.

Producing Consistent and Sustainable Results

As we took steps to secure the necessary merger approvals, we continued to make solid progress in strengthening the performance of our business units and our overall financial position.

With completion of the Air Quality Compliance project at the W.H. Sammis Plant, we expect lower capital expenditures in the future. In addition, we produced $215 million in cash through the sale of the Sumpter Plant in Michigan and a 6.65 percent interest in the power generated by the facilities of the Ohio Valley Electric Corporation. And, we continue to evaluate opportunities to divest other non-core assets.

We increased our liquidity by more than $400 million. We also completed a $350 million term loan agreement for Signal Peak, the Montana coal mine in which we have an equity investment, with the proceeds used to pay down our revolving credit facility. In addition, we refinanced or remarketed more than $700 million of pollution control revenue bonds and, importantly, generated approximately $3.1 billion in cash from operations.

On the regulated side of our business, electricity deliveries increased nearly 6 percent in 2010 compared with the previous year, reflecting the moderate recovery of the economy and favorable weather. Deliveries to industrial customers were up 8 percent – primarily related to increased activity in the steel, automotive and related industries – and have recovered to about 90 percent of 2007's pre-recession levels. Residential usage was at its highest level in nearly a decade, primarily due to warmer-than-normal weather in the summer.

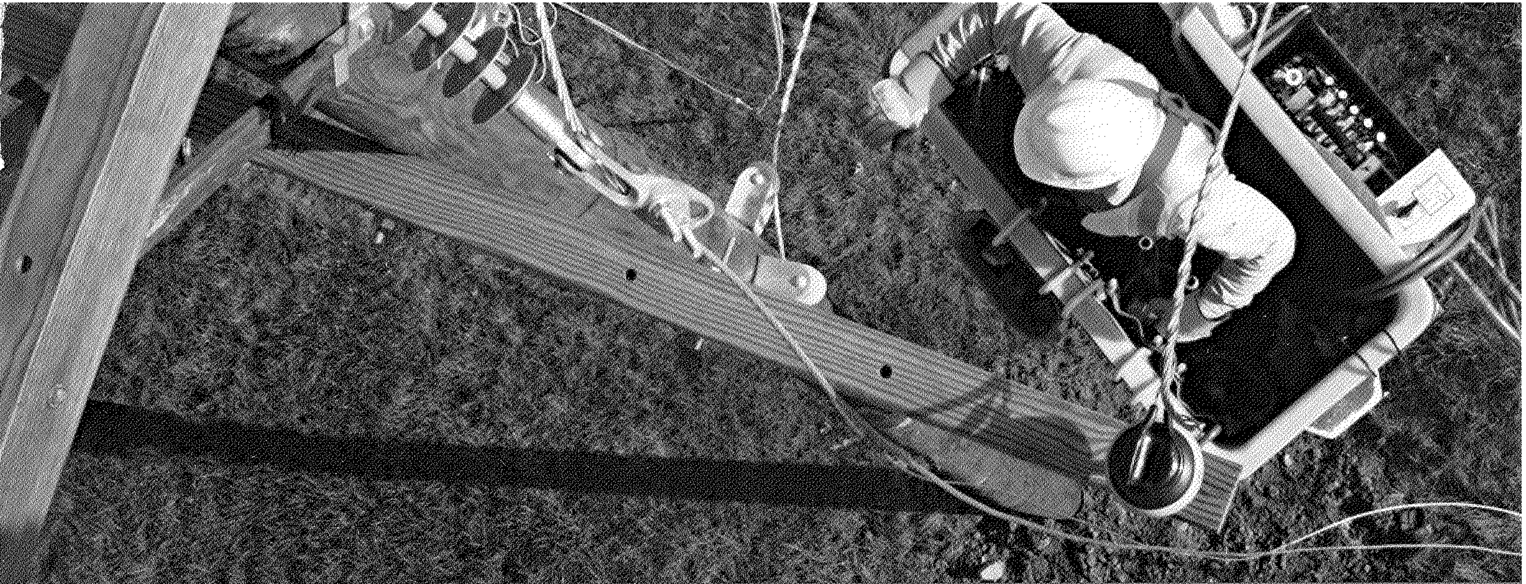
We also achieved solid results for transmission and distribution reliability. In recognition of our outstanding reliability performance, we received PA Consulting Group's 2010 ReliabilityOne™ Award in the Midwest Region.

We're taking steps to further enhance the operational performance of our competitive generating fleet. For example, we announced plans to replace the reactor head at the Davis-Besse Nuclear Power Station during an outage scheduled for the fall of this year, accelerating the original replacement timetable by almost three years.

Employees at our Customer Contact Centers handled more than 10.8 million customer calls in 2010 – with three out of four customers rating the interactions as excellent.

In addition, the Nuclear Regulatory Commission accepted our application to renew Davis-Besse's operating license – an important step toward keeping this asset productive for years to come.

We also lowered costs and enhanced our operating flexibility by reducing operations at our smaller, coal-fired plants located along Lake Erie. And, despite our best efforts to overcome a number of challenges, we cancelled plans to repower our R.E. Burger Plant with biomass. These actions were taken in response to the economy's impact on power markets.



In addition, we are nearing completion of our effort to consolidate our transmission operations into the PJM Interconnection. Recent filings with the Federal Energy Regulatory Commission keep us on track to meet our June 1, 2011, target date.

Safety remains a key priority in every facet of our business. Employees throughout our Company strive to achieve an accident-free workplace by taking personal responsibility for their safety as well as the safety of their coworkers. I'm especially proud of our Ohio Edison and Penn Power employees, who reached a significant safety milestone by working more than six million hours without a lost-time accident – among the best safety performances in our industry.

Pursuing Strategic, Generation-Backed Sales Opportunities

We continue to strengthen our competitive position as we grow our retail business.

During the year, our competitive subsidiary, FirstEnergy Solutions (FES), achieved a sixfold increase in the amount of electricity it sold to governmental aggregation groups – from 1.9 million megawatt-hours (MWH) to 12.8 million MWH – and more than doubled direct retail sales, primarily to industrial and commercial customers. FES is now one of the largest retail suppliers of electricity in the country.

Building on this progress, FES continues to execute a competitive retail strategy that combines the strength of our low-cost, efficient fleet of power plants with a focused sales effort. The addition of the Allegheny Energy generating fleet further enhances our retail strategy by substantially increasing our available product and expanding the markets into which we can effectively and efficiently deliver that generation. With our generating plants located within or near these markets, we target customers whose usage is closely aligned with the capabilities of our generating fleet.

Several recent initiatives also are expected to help us expand our customer base in 2011 and beyond. Working in partnership with Chamber*Choice* – a group purchasing firm representing more than 90 Pennsylvania chambers of commerce – FES has enrolled more than 8,000 chamber members in western Pennsylvania. In addition, FES is expanding into new markets outside our traditional utility service areas by acquiring retail customers in southern Ohio, Michigan and Illinois.

(Above) *A student works on de-energized lines at one of our Power Systems Institute (PSI) facilities. PSI trains the next generation of employees in line and substation work.*

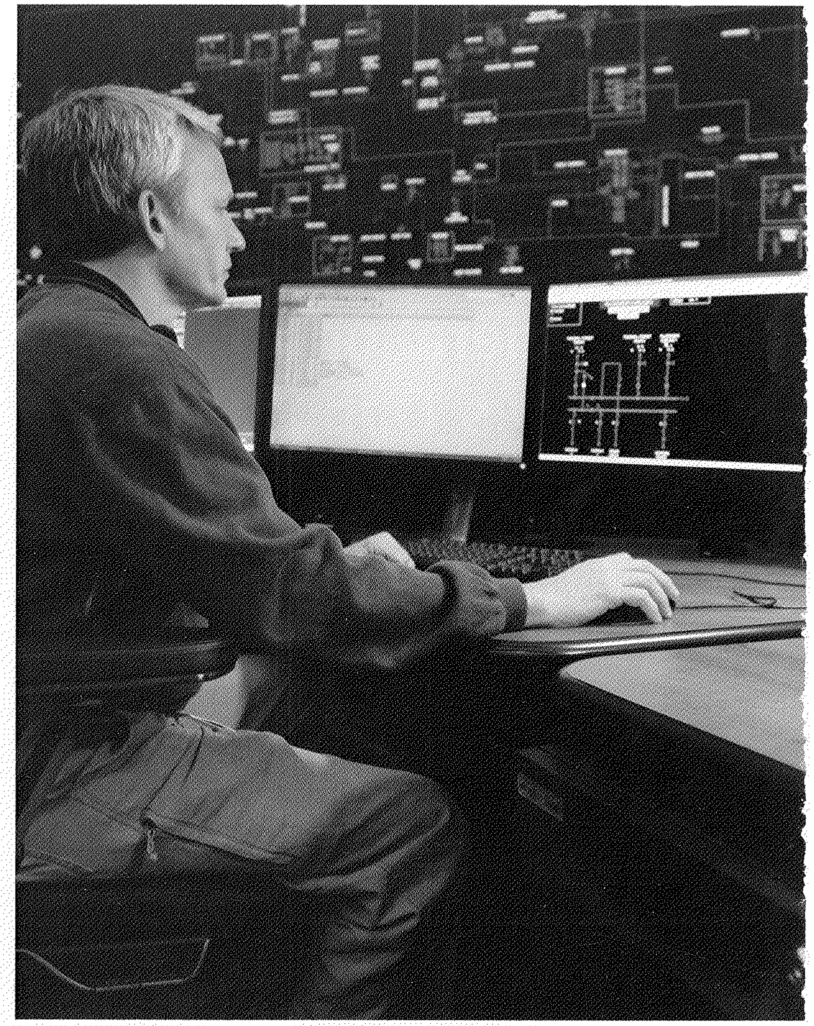
Successful Transition to Competitive Markets

We completed the transition to fully competitive retail markets for electricity in Pennsylvania.

In January of this year, Met-Ed, Penelec and our newly acquired West Penn Power utility began offering market rates for generation – set through wholesale power purchases – to customers who do not choose alternative suppliers.

With this process now in place throughout our Pennsylvania service area, all of our utilities outside of West Virginia now offer customers market-based pricing for generation.

In Ohio, the Public Utilities Commission approved our three-year stipulated Electric Security Plan (ESP), which was supported by a broad coalition representing residential, business and low-income customers. Under this plan, the generation portion of electric rates for the period of June 2011 through May 2014 will be determined through a competitive bidding process. The first of these auctions occurred in October 2010 and the second took place in January 2011. While base distribution rates will remain in place, the plan enables us to recover costs necessary to maintain and enhance our distribution system. In addition, the plan provides rate stability for customers, outlines support for energy efficiency, and encourages job creation and economic development in our communities.



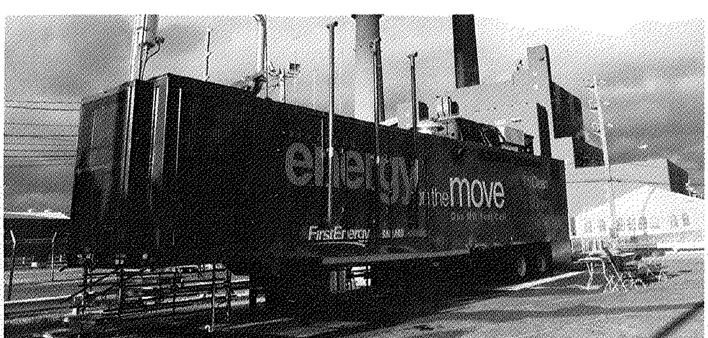
At our new transmission system control facility in Fairmont, W.Va., dispatchers use state-of-the-art technology to monitor electric reliability.

Protecting the Environment

We continue to work to minimize the impact of our operations on the environment while meeting our customers' needs for safe, reliable electricity.

With the completion of our merger with Allegheny Energy, more than 80 percent of our fleet is non-emitting nuclear, low-emitting natural gas and scrubbed coal. And, with our hydroelectric, pumped-storage and wind resources, we have nearly 2,200 MW of renewable capacity available.

We further enhanced the environmental performance of our generating fleet with the completion of the $1.8 billion retrofit of our W.H. Sammis Plant – one of the largest emission control projects in the United States. Due to the dedication and cooperation of employees, contractors, suppliers and local communities throughout the construction process, this award-winning environmental retrofit was completed on time and under budget.



At our Eastlake Plant in Ohio, we began a multi-year test of the world's largest utility-scale fuel cell of its kind. Dubbed "megawatt-in-a-box," this mobile facility can provide peaking generation when and where it's needed most.

The project was recognized as the industry's construction project of the year at the 2010 *Platts* Global Energy Awards and received honors from *Power Engineering* magazine.

We also continue to pursue new sources of clean, renewable energy and other opportunities to meet our customers' energy needs in an environmentally sound manner. For example, in collaboration with Ballard Power Systems of Vancouver, British Columbia, we began a five-year test of a one-MW hydrogen-powered fuel cell located at our Eastlake Plant to better understand this technology's ability to provide power during periods of peak demand.

We announced plans to accelerate the replacement of the reactor head at our Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, to further enhance safe and reliable operations at the plant.

In addition, we recently agreed to purchase 100 MW of output from the Blue Creek Wind Farm – the first large-scale wind operation to begin construction in Ohio. By bringing our total amount of available wind power to nearly 500 MW, this project will strengthen our position as one of the largest providers of renewable energy in the region.

Meeting Future Challenges

We recognize that our Company and industry continue to face significant challenges, including current soft market prices for power, a slow economic recovery and uncertainty around environmental requirements.

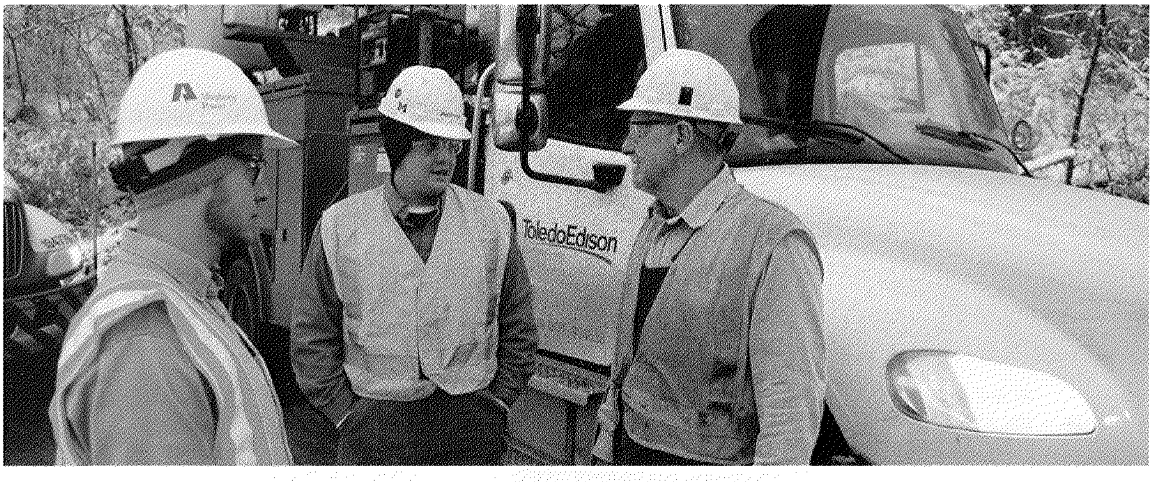
In addition, renewable energy requirements that involve intermittent solar and wind generation will add complexity and expense to our operations. And, compliance with rigorous energy efficiency mandates will impose considerable costs on our customers and Company.

However, I am confident we can address these and other challenges by remaining focused on safety, operational excellence and financial discipline. And, as we build on our dual platform of regulated and competitive businesses, we will create new opportunities for growth across the entire electric power value chain.

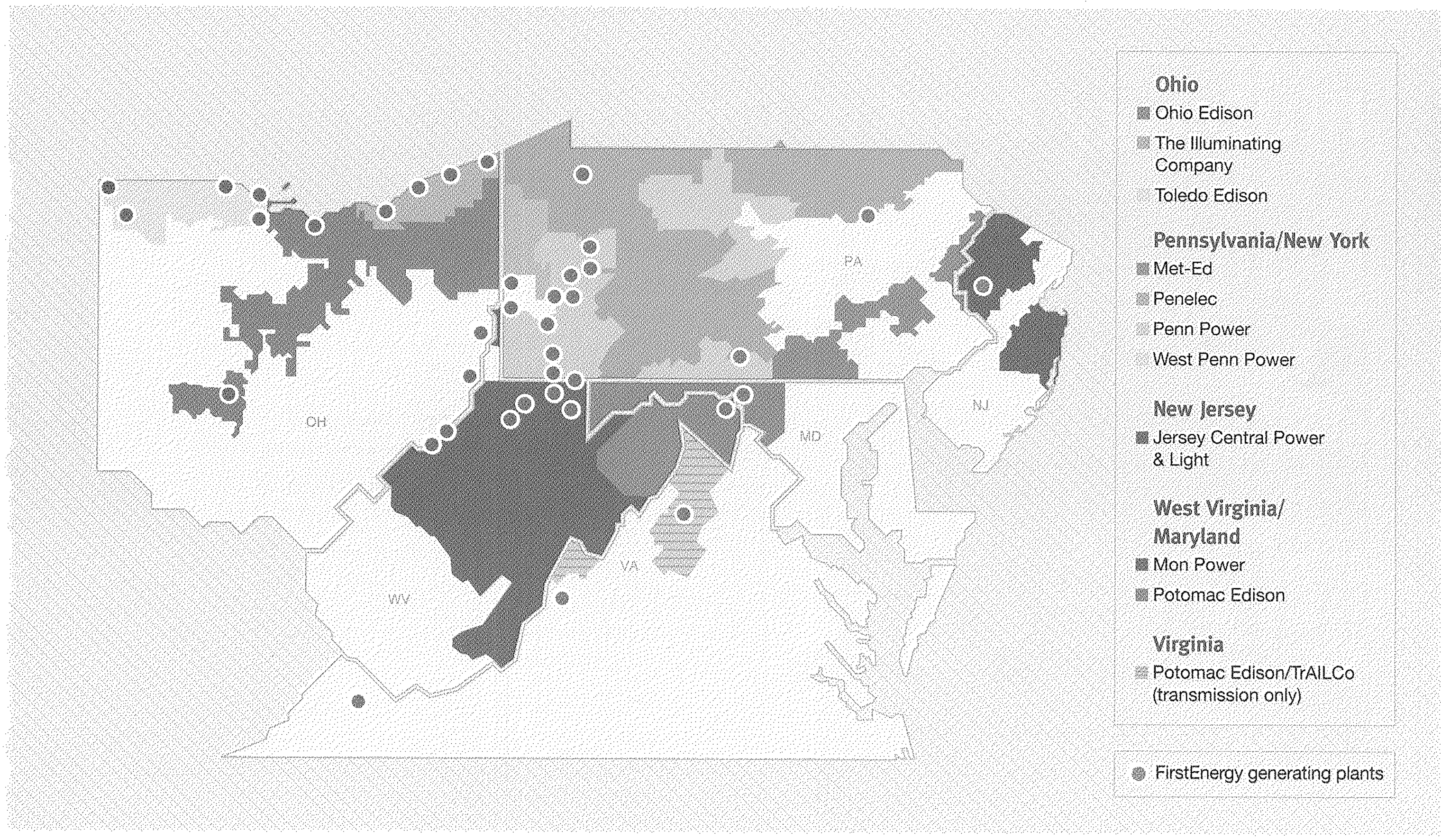
I'd like to thank the management teams and employees of FirstEnergy and Allegheny Energy for expeditiously completing our merger and building a stronger foundation for our Company. I look forward to the future as we bring the many benefits of the new FirstEnergy to our shareholders, customers and employees.

Sincerely,

Anthony J. Alexander
President and Chief Executive Officer
March 21, 2011



As a result of the merger, our operating companies have more resources available to provide mutual assistance following major storms.



Corporate Profile

FirstEnergy is a leading regional energy provider headquartered in Akron, Ohio. Our subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services.

Our 10 utility operating companies comprise the nation's largest investor-owned electric system based on six million customers served within a nearly 65,000-square-mile area of Ohio, Pennsylvania, Maryland, West Virginia, New Jersey and New York.

Our generation subsidiaries control approximately 24,000 MW of capacity from a diversified mix of regional coal, nuclear, natural gas, oil, hydroelectric, pumped-storage and contracted wind resources – including more than 2,200 MW of renewable energy. The Company's transmission subsidiaries operate nearly 20,000 miles of high-voltage transmission lines connecting the Midwest and Mid-Atlantic regions.

FirstEnergy Board of Directors

Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (Citigroup).

Anthony J. Alexander
President and Chief Executive Officer of FirstEnergy Corp.

Michael J. Anderson
Chairman of the Board, President and Chief Executive Officer of The Andersons, Inc.

Dr. Carol A. Cartwright
President of Bowling Green State University. Retired President of Kent State University.

William T. Cottle
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company.

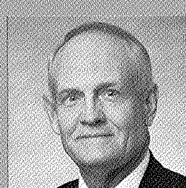
Robert B. Heisler, Jr.
Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.

Julia L. Johnson
President of NetCommunications, LLC.

Ted J. Kleisner
Chief Executive Officer of Hershey Entertainment & Resorts Company.

Ernest J. Novak, Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.

Catherine A. Rein
Retired, formerly Senior Executive Vice President and Chief Administrative Officer of MetLife, Inc.



George M. Smart
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc.

Wes M. Taylor
Retired, formerly President of TXU Generation.

Jesse T. Williams, Sr.
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company.

Dear Shareholders:

On behalf of your Board of Directors, I congratulate our management team and employees for successfully completing the merger of FirstEnergy and Allegheny Energy. Through this combination, we are creating a premier regional energy provider that is well positioned for future success.

I welcome Julia Johnson and Ted Kleisner, who were appointed to the Board in February 2011. Julia, who previously served as a director of Allegheny Energy, is the President of NetCommunications, LLC, and a director of American Water Works Company, Inc., MasTec, Inc. and NorthWestern Corporation. Ted, who also served on the Allegheny Energy Board, is the Chief Executive Officer of Hershey Entertainment and Resorts Company and former President of CSX Hotels, Inc.

As your Company remains focused on delivering solid results for shareholders, FirstEnergy is committed to protecting the environment, promoting public health and safety, sustaining good corporate governance practices, and supporting the communities we serve.

Based on our confidence in the Company's future, your Board maintained the annual dividend rate of $2.20 per share in 2010. In keeping with Board policy, we will continue to review the dividend on a quarterly basis as FirstEnergy achieves the anticipated benefits of the merger, continues to strengthen its position in competitive markets, and creates new opportunities for future growth.

Your Board appreciates your ongoing support. We look forward to working with our management team to realize the full potential of FirstEnergy.

Sincerely,

George M Smart

George M. Smart
Chairman of the Board

FirstEnergy Corp. Officers

Anthony J. Alexander**
President and Chief Executive Officer

Paul J. Evanson
Executive Vice Chairman

Mark T. Clark*
Executive Vice President and Chief Financial Officer

Gary R. Leidich**
Executive Vice President

Leila L. Vespoli*
Executive Vice President and General Counsel

Charles E. Jones**
President, FirstEnergy Utilities

Rhonda S. Ferguson*
Vice President and Corporate Secretary

James F. Pearson*
Vice President and Treasurer

Harvey L. Wagner*
Vice President, Controller and Chief Accounting Officer

Kevin R. Burgess*
Assistant Controller

Jacqueline S. Cooper*
Assistant Corporate Secretary

Dena R. McKee*
Assistant Controller

Randy Scilla**
Assistant Treasurer

Steven R. Staub*
Assistant Treasurer

K. Jon Taylor**
Assistant Controller

Edward J. Udovich**
Assistant Corporate Secretary

* Also holds a similar position with FirstEnergy Service Company, FirstEnergy Solutions Corp., and FirstEnergy Nuclear Operating Company.

** Also holds a similar position with FirstEnergy Service Company.

Forward-Looking Statement

This annual report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry, the impact of the regulatory process on the pending matters in the various states in which we do business including, but not limited to, matters related to rates, the status of the Potomac-Appalachian Transmission Highline (PATH) project in light of PJM Interconnection, LLC's efforts to determine whether the need for PATH should be re-evaluated and the related suspension of work on the project, PATH's rate of recovery at FERC, business and regulatory impacts from American Transmission Systems, Incorporated's realignment into PJM Interconnection, LLC, 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 greenhouse gas emission and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace the Clean Air Interstate Rules, the uncertainty of the timing and amounts of the capital expenditures needed to complete, among other things, the PATH project as a result of its current suspension status, the uncertainty of the timing and amounts of the capital expenditures needed to resolve any New Source Review 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 Nuclear Regulatory Commission), adverse legal decisions and outcomes related to Metropolitan Edison Company's and Pennsylvania Electric Company'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 FirstEnergy's 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 company, the state of the capital and credit markets affecting the company, interest rates and any actions taken by credit rating agencies that could negatively affect FirstEnergy's access to financing or its costs and increase its requirements to post additional collateral to support outstanding commodity positions, letters of credit and other financial guarantees, the continuing uncertainty of the national and regional economy and its impact on the company's major industrial and commercial customers, issues concerning the soundness of financial institutions and counterparties with which FirstEnergy does business, issues arising from the recently completed merger of FirstEnergy and Allegheny Energy, Inc. and the ongoing coordination of their combined operations, including FirstEnergy's 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 and the risks and other factors discussed from time to time in FirstEnergy's Securities and Exchange Commission 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. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

Annual Report 2010

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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.
Allegheny	Allegheny Energy, Inc. is the parent holding company of Allegheny Supply, Monongahela Power Company, The Potomac Edison Company and West Penn Power Company
ALJ	Administrative Law Judge
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
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)

GLOSSARY OF TERMS, Cont'd.

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
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

GLOSSARY OF TERMS, Cont'd.

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

FIRSTENERGY CORP.

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

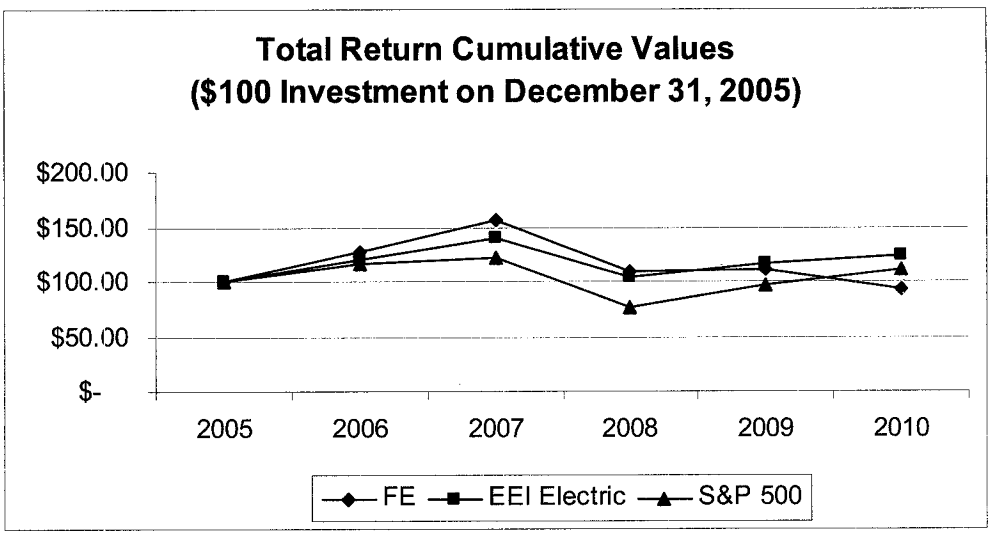
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	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.



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.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

FIRSTENERGY CORP.

MANAGEMENT DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry.
- The impact of the regulatory process on the pending matters 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.

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.

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.

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.

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 complete; 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.

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.

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;

- 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;

- 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:

	2010	2009	2008	Increase (Decrease) 2010 vs 2009	Increase (Decrease) 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.

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.

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)

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.

  The following table summarizes the sources of changes in purchased power costs:

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

Source of Change in Wholesale Revenues	Increase Decrease
	(In millions)
POLR:	
Effect of 5.3% decrease in sales volumes	$ (153)
Change in prices	(274)
	(427)
Other Wholesale:	
Effect of 26.5% decrease in sales volumes	(105)
Change in prices	23
	(82)
Net Decrease in Wholesale Revenues	$ (509)

Expenses -

Total expenses increased $1.5 billion in 2010 due to the following factors:

- Fuel costs increased $287 million in 2010 compared to 2009 primarily due to increased volumes consumed ($217 million) and higher unit prices ($70 million). The higher volumes consumed in 2010 were due to increased sales to direct and government aggregation customers, improved economic conditions and improved generating unit availability. The increase in unit prices was due primarily to increased coal transportation costs and to higher nuclear fuel unit prices following the refueling outages that occurred in 2009 and 2010.

- Purchased power costs increased $728 million. Increased volumes purchased primarily relate to the assumption of a 1,300 MW third party contract from Met-Ed and Penelec.

- Fossil operating costs decreased $12 million due primarily to lower labor and professional and contractor costs, which were partially offset by reduced gains from the sale of emission allowances and excess coal.

- Nuclear operating costs decreased $21 million due primarily to lower labor, consulting and contractor costs partially offset by increased nuclear property insurance and employee benefit costs. The year 2010 had one less refueling outage and fewer extended outages than the same period of 2009.

- Transmission expenses increased $25 million due primarily to increased costs in MISO of $170 million from higher network, ancillary and congestion costs, partially offset by lower PJM transmission expenses of $145 million due to lower congestion costs.

- Depreciation expense decreased $16 million principally due to reduced depreciable property associated with the impairments described below and the sale of the Sumpter plant in early 2010.

- General taxes increased $5 million due to an increase in revenue-related taxes.

- Other expenses increased $465 million primarily due to a $384 million impairment charge ($240 million net of tax) related to operational changes at certain smaller coal-fired units in response to the continued slow economy, lower demand for electricity and uncertainty related to proposed new federal environmental regulations. Expenses were also increased due to the significant growth in FES' retail business -- professional and contractor expenses, billings from affiliated service companies, uncollectible customer accounts and agent fees.

Other Expense –

Total other expense in 2010 was $93 million higher than the same period in 2009, primarily due to a decrease in nuclear decommissioning trust investment income ($66) million and a $23 million increase in net interest expense from new long-term debt issued in late 2009 combined with the restructuring of outstanding PCRBs that occurred throughout 2009 and 2010.

Other – 2010 Compared to 2009

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $135 million decrease in earnings available to FirstEnergy in 2010 compared to 2009. The decrease resulted primarily from increased income tax expense ($342 million) due in part to the absence of favorable tax settlements that occurred in 2009 ($200 million), partially offset by the absence of 2009 debt retirement costs in connection with the tender offer for holding company debt ($90 million), decreased interest expense associated with the debt retirement ($53 million), increased investment income ($20 million) and decreased depreciation ($20 million).

Summary of Results of Operations – 2009 Compared with 2008

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

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 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.

2008 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 11,360	$ 1,333	$ -	$ 12,693
Other	708	238	(12)	934
Internal	-	2,968	(2,968)	-
Total Revenues	12,068	4,539	(2,980)	13,627
Expenses:				
Fuel	2	1,338	-	1,340
Purchased power	6,480	779	(2,968)	4,291
Other operating expenses	2,022	1,142	(119)	3,045
Provision for depreciation	417	243	17	677
Amortization of regulatory assets	1,053	-	-	1,053
Deferral of new regulatory assets	(316)	-	-	(316)
Impairment of long lived assets	-	-	-	-
General taxes	646	109	23	778
Total Expenses	10,304	3,611	(3,047)	10,868
Operating Income	1,764	928	67	2,759
Other Income (Expense):				
Investment income	171	(34)	(78)	59
Interest expense	(411)	(152)	(191)	(754)
Capitalized interest	3	44	5	52
Total Other Expense	(237)	(142)	(264)	(643)
Income Before Income Taxes	1,527	786	(197)	2,116
Income taxes	611	314	(148)	777
Net Income	916	472	(49)	1,339
Loss attributable to noncontrolling interest	-	-	(3)	(3)
Earnings available to FirstEnergy Corp.	$ 916	$ 472	$ (46)	$ 1,342

Changes Between 2009 and 2008 Financial Results Increase (Decrease)	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ (775)	$ 114	$ -	$ (661)
Other	(149)	209	(70)	(10)
Internal*	-	(125)	142	17
Total Revenues	(924)	198	72	(654)
Expenses:				
Fuel	(2)	(185)	-	(187)
Purchased power	80	217	142	439
Other operating expenses	(598)	215	35	(348)
Provision for depreciation	28	27	4	59
Amortization of regulatory assets	102	-	-	102
Deferral of new regulatory assets	180	-	-	180
Impairment of long lived assets	-	6	-	6
General taxes	(5)	(1)	(19)	(25)
Total Expenses	(215)	279	162	226
Operating Income	(709)	(81)	(90)	(880)
Other Income (Expense):				
Investment income	(32)	155	22	145
Interest expense	(61)	(14)	(149)	(224)
Capitalized interest	-	16	62	78
Total Other Expense	(93)	157	(65)	(1)
Income Before Income Taxes	(802)	76	(155)	(881)
Income taxes	(321)	31	(242)	(532)
Net Income	(481)	45	87	(349)
Loss attributable to noncontrolling interest	-	-	(13)	(13)
Earnings available to FirstEnergy Corp.	$ (481)	$ 45	$ 100	$ (336)

* 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 – 2009 Compared to 2008

Net income decreased $481 million to $435 million in 2009 compared to $916 million in 2008, primarily due to lower revenues, increased purchased power costs and decreased deferrals of new regulatory assets, partially offset by lower other operating 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	$ 3,420	$ 3,882	$ (462)
Generation sales:			
Retail	5,760	5,768	(8)
Wholesale	752	962	(210)
Total generation sales	6,512	6,730	(218)
Transmission	1,023	1,268	(245)
Other	189	188	1
Total Revenues	$ 11,144	$ 12,068	$ (924)

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

Electric Distribution KWH Deliveries	
Residential	(3.3)%
Commercial	(4.4)%
Industrial	(14.7)%
Total Distribution KWH Deliveries	(7.3)%

The lower revenues from distribution services were driven primarily by the reductions in sales volume associated with milder weather and economic conditions. The decrease in residential deliveries reflected reduced weather-related usage compared to 2008, as cooling degree days and heating degree days decreased by 17% and 1%, respectively. The decreases in distribution deliveries to commercial and industrial customers were primarily due to economic conditions in FirstEnergy's service territory. In the industrial sector, KWH deliveries declined to major automotive customers by 20.2% and to steel customers by 36.2%. Reduced revenues from transition charges for OE and TE that ceased with the full recovery of related costs effective January 1, 2009 and the transition rate reduction for CEI effective June 1, 2009, were offset by PUCO-approved distribution rate increases (see Regulatory Matters – Ohio).

The following table summarizes the price and volume factors contributing to the $218 million decrease in generation revenues in 2009 compared to 2008:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 10.5% decrease in sales volumes	$ (603)
Change in prices	595
	(8)
Wholesale:	
Effect of 14.9% decrease in sales volumes	(143)
Change in prices	(67)
	(210)
Net Decrease in Generation Revenues	$ (218)

The decrease in retail generation sales volumes from 2008 was primarily due to the weakened economic conditions and milder weather described above. Retail generation prices increased for JCP&L and Penn during 2009 as a result of their power procurement processes. For the Ohio Companies, average prices increased primarily due to the higher fuel cost recovery riders that were effective from January through May 2009. In addition, effective June 1, 2009, the Ohio Companies' transmission tariff ended and transmission costs became a component of the generation rate established under the CBP.

Wholesale generation sales decreased principally as a result of JCP&L selling less available power from NUGs due to the termination of a NUG purchase contract in October 2008. The decrease in wholesale prices reflected lower spot market prices in PJM.

Transmission revenues decreased $245 million primarily due to the termination of the Ohio Companies' current transmission tariff and lower MISO and PJM transmission revenues, partially offset by higher transmission rates for Met-Ed and Penelec resulting from the annual updates to their TSC riders (see Regulatory Matters). The difference between transmission revenues accrued and transmission costs incurred are deferred, resulting in no material effect on current period earnings.

Expenses –

Total expenses increased by $215 million due to the following:

- Purchased power costs were $80 million higher in 2009 due to higher unit costs, partially offset by an increase in volumes combined with higher NUG cost deferrals. The increased purchased power costs from non-affiliates was due primarily to increased volumes for the Ohio Companies as a result of their CBP, partially offset by lower volumes for Met-Ed and Penelec due to the termination of a third-party supply contract in December 2008 and for JCP&L due to the termination of a NUG purchase contract in October 2008. Decreased purchased power costs from FES were principally due to lower volumes for the Ohio Companies following their CBP, partially offset by increased volumes for Met-Ed and Penelec under their fixed-price partial requirements PSA with FES. Higher unit costs from FES, which included a component for transmission under the Ohio Companies' CBP, partially offset the decreased volumes.

The following table summarizes the sources of changes in purchased power costs:

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 58
Change due to increased volumes	312
	370
Purchases from FES:	
Change due to increased unit costs	583
Change due to decreased volumes	(725)
	(142)
Increase in NUG costs deferred	(148)
Net Increase in Purchased Power Costs	$ 80

- Transmission expenses were lower by $481 million in 2009, reflecting the change in the transmission tariff under the Ohio Companies' CBP, reduced transmission volumes and lower congestion costs.

- Intersegment cost reimbursements related to the Ohio Companies' nuclear generation leasehold interests increased by $114 million in 2009. Prior to 2009, a portion of OE's and TE's leasehold costs were recovered through customer transition charges. Effective January 1, 2009, these leasehold costs are reimbursed from the competitive energy services segment.

- Labor and employee benefit expenses decreased by $39 million reflecting changes to Energy Delivery's organizational and compensation structure and increased resources dedicated to capital projects, partially offset by higher pension expenses resulting from reduced pension plan asset values at the end of 2008.

- Storm-related costs were $16 million lower in 2009 compared to the prior year.

- An increase in other operating expenses of $40 million resulted from the recognition of economic development and energy efficiency obligations in accordance with the PUCO-approved ESP.

- Uncollectible expenses were higher by $12 million in 2009 principally due to increased bankruptcies.

- A $102 million increase in the amortization of regulatory assets was due primarily to the ESP-related impairment of CEI's regulatory assets ($216 million) and MISO/PJM transmission cost amortization in 2009, partially offset by the cessation of transition cost amortization for OE and TE.

- A $180 million decrease in the deferral of new regulatory assets was principally due to the absence in 2009 of PJM transmission cost deferrals and RCP distribution cost deferrals, partially offset by the PUCO-approved deferral of purchased power costs for CEI.

- Depreciation expense increased $28 million due to property additions since 2008.

- General taxes decreased $5 million due primarily to lower revenue-related taxes in 2009.

Other Expense –

Other expense increased $93 million in 2009 compared to 2008. Lower investment income of $32 million resulted primarily from repaid notes receivable from affiliates. Higher interest expense (net of capitalized interest) of $61 million resulted from a net increase in debt of $1.8 billion by the Utilities and ATSI during 2009.

Competitive Energy Services – 2009 Compared to 2008

Net income increased to $517 million in 2009 compared to $472 million in the same period of 2008. The increase in net income includes FGCO's gain from the sale of a 9% participation interest in OVEC, increased sales margins, and an increase in investment income, offset by a mark-to-market adjustment relating to purchased power contracts for delivery in 2010 and 2011.

Revenues –

Total revenues increased $198 million in 2009 compared to the same period in 2008. This increase primarily resulted from the OVEC sale and higher unit prices on affiliated generation sales to the Ohio Companies and non-affiliated customers, partially offset by lower sales volumes.

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

Revenues by Type of Service	2009	2008	Increase (Decrease)
		(In millions)	
Non-Affiliated Generation Sales:			
Retail	$ 778	$ 615	$ 163
Wholesale	669	718	(49)
Total Non-Affiliated Generation Sales	1,447	1,333	114
Affiliated Generation Sales	2,843	2,968	(125)
Transmission	73	150	(77)
Sale of OVEC participation interest	252	-	252
Other	122	88	34
Total Revenues	$ 4,737	$ 4,539	$ 198

The increase in non-affiliated retail revenues of $163 million resulted from increased revenue in both the PJM and MISO markets. The increase in MISO retail revenue is primarily the result of the acquisition of new customers, higher unit prices and the inclusion of the transmission related component in retail rates previously reported as transmission revenues. The increase in PJM retail revenue resulted from the acquisition of new customers, higher sales volumes and unit prices. The acquisition of new customers in MISO is primarily due to new government aggregation contracts with 60 area communities in Ohio that will provide discounted generation prices to approximately 580,000 residential and small commercial customers. Lower non-affiliated wholesale revenues of $49 million resulted from decreased sales volumes in PJM partially offset by increased capacity prices, increased sales volumes in MISO, and favorable settlements on hedged transactions.

The lower affiliated company wholesale generation revenues of $125 million were due to lower sales volumes to the Ohio Companies combined with lower unit prices to the Pennsylvania companies, partially offset by higher unit prices to the Ohio Companies and increased sales volumes to the Pennsylvania Companies. The lower sales volumes and higher unit prices to the Ohio Companies reflected the results of the power procurement processes in the first half of 2009 (see Regulatory Matters – Ohio). The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements supplied by FES partially offset by lower sales to Penn due to decreased default service requirements in 2009 compared to 2008. Additionally, while unit prices for each of the Pennsylvania Companies did not change, the mix of sales among the companies caused the overall price to decline.

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

Source of Change in Non-Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 8.6% increase in sales volumes	$ 53
Change in prices	110
	163
Wholesale:	
Effect of 13.9% decrease in sales volumes	(100)
Change in prices	51
	(49)
Net Increase in Non-Affiliated Generation Revenues	$ 114

Source of Change in Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 36.3% decrease in sales volumes	$ (837)
Change in prices	645
	(192)
Wholesale:	
Effect of 14.7% increase in sales volumes	97
Change in prices	(30)
	67
Net Decrease in Affiliated Generation Revenues	$ (125)

Transmission revenues decreased $77 million due primarily to reduced loads following the expiration of the government aggregation programs in Ohio at the end of 2008 and to the inclusion of the transmission-related component in the retail rates in mid-2009. In 2009 FGCO sold 9% of its participation interest in OVEC resulting in a $252 million ($158 million, after tax) gain. Other revenue increased $28 million primarily due to income associated with NGC's acquisition of equity interests in the Perry and Beaver Valley Unit 2 leases.

Expenses -

Total expenses increased $279 million in 2009 due to the following factors:

- Fossil Fuel costs decreased $198 million due primarily to lower generation volumes ($307 million) partially offset by higher unit prices ($109 million). Nuclear Fuel costs increased $13 million as higher unit prices ($26 million) were partially offset by lower generation ($13 million).

- Purchased power costs increased $217 million due to a mark-to-market adjustment ($205 million) relating to purchased power contracts for delivery in 2010 and 2011 and higher unit prices ($33 million) that resulted primarily from higher capacity costs, partially offset by lower volumes purchased ($21 million) due to FGCO's reduced participation interest in OVEC.

- Fossil operating costs decreased $24 million due primarily to a reduction in contractor, material and labor costs and increased resources dedicated to capital projects, partially offset by higher employee benefits.

- Nuclear operating costs increased $45 million due to an additional refueling outage during the 2009 period and higher employee benefits, partially offset by lower labor costs.

- Transmission expense increased $121 million due to transmission services charges related to the load serving entity obligations in MISO, increased net congestion and higher loss expenses in MISO and PJM.

- Other expense increased $78 million due primarily to increased intersegment billings for leasehold costs from the Ohio Companies and higher pension costs.

- Depreciation expense increased $27 million due to NGC's increased ownership interest in Beaver Valley Unit 2 and Perry.

Other Income (Expense) –

Total other income in 2009 was $15 million compared to total other expense in 2008 of $142 million, resulting primarily from a $155 million increase from gains on the sale of nuclear decommissioning trust investments. During 2009, the majority of the nuclear decommissioning trust holdings were converted to more closely align with the liability being funded.

Other – 2009 Compared to 2008

Our financial results from other operating segments and reconciling items resulted in a $100 million increase in net income in 2009 compared to 2008. The increase resulted primarily from $200 million of favorable tax settlements, offset by debt redemption costs of $90 million and by the absence of the gain from the sale of telecommunication assets ($19 million, net of taxes) in 2008.

POSTRETIREMENT BENEFITS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of our employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. We also provide health care benefits, which include certain employee contributions, deductibles, and co-payments, upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. Benefit plan assets and obligations are remeasured annually using a December 31 measurement date. Adverse market conditions during 2008 increased 2009 costs, which were partially offset by the effects of a $500 million voluntary cash pension contribution and an OPEB plan amendment in 2009. Recovering market conditions and greater returns on higher asset levels decreased postretirement benefit expense in 2010, partially offset by a full year of realization on the reduction in benefit liability resulting from the OPEB plan amendment in 2009. Pension and OPEB expenses are included in various cost categories and have contributed to cost increases discussed above for 2010. The following table reflects the portion of qualified and non-qualified pension and OPEB costs that were charged to expense in the three years ended December 31, 2010:

Postretirement Benefits Expense (Credits)	2010	2009	2008
		(In millions)	
Pension	$ 174	$ 185	$ (23)
OPEB	(90)	(40)	(37)
Total	$ 84	$ 145	$ (60)

As of December 31, 2010, our pension plan was underfunded and we currently anticipate that an additional voluntary cash contribution of $250 million will be made in 2011.

The overall actual investment result during 2010 was a gain of 10% compared to an assumed 8.5% return. Based on discount rates of 5.50% for pension, 5.00% for OPEB and an estimated return on assets of 8.25%, our 2011 pre-tax net periodic postretirement benefit expense is expected to be approximately $92 million.

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.

CAPITAL RESOURCES AND LIQUIDITY

As of December 31, 2010, FirstEnergy had cash and cash equivalents of approximately $1 billion available to fund investments, operations and capital expenditures. To fund liquidity and capital requirements for 2011 and beyond, FirstEnergy may rely on internal and external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through issuances of debt and/or equity securities.

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 a combination of internal cash from operations and external funds from 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.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy's ability to fund current liquidity and capital resource requirements. To mitigate risk, FirstEnergy's business model stresses financial discipline and a strong focus on execution. Major elements of this business model include the expectation of: projected cash from operations, opportunities for favorable long-term earnings growth as the transition to competitive generation markets is completed, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt, commitment to a secure dividend (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) and a successful merger integration.

As of December 31, 2010, FirstEnergy's net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of December 31, 2010, included the following (in millions):

Currently Payable Long-term Debt		
PCRBs supported by bank LOCs [1]	$	827
FGCO and NGC PCRBs [1]		191
Penelec unsecured PCRBs		25
FirstEnergy Corp. unsecured note		250
NGC collateralized lease obligation bonds		50
Sinking fund requirements		33
FES term loan		100
Other obligations		10
	$	1,486

(1) Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had approximately $700 million of short-term borrowings as of December 31, 2010 and $1.1 billion as of December 31, 2009. FirstEnergy's available liquidity as of January 31, 2011, is summarized 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.

On October 22, 2010, Signal Peak and Global Rail, as borrowers, entered into a $350 million syndicated two-year senior secured term loan facility. The loan proceeds were used to repay $258 million of notes payable to FirstEnergy, including $9 million of interest and $63 million of bank loans that were scheduled to mature on November 16, 2010. Additional proceeds were used for general company purposes, including an $11 million repayment of a third-party seller's note. As discussed below under Guarantees and Other Assurances, FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership with FEV in the borrowers, have provided a guaranty of the borrowers' obligations under the facility.

Revolving Credit Facility

FirstEnergy has the capability to request an increase in the total commitments available under the $2.75 billion revolving credit facility (included in the borrowing capability table above) up to a maximum of $3.25 billion, subject to the discretion of each lender to provide additional commitments. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitment. 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 following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2010:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ - (1)
FES	1,000	- (1)
OE	500	500
Penn	50	34 (2)
CEI	250 (3)	500
TE	250 (3)	500
JCP&L	425	411 (2)
Met-Ed	250	300 (2)
Penelec	250	300 (2)
ATSI	50 (4)	100

(1) No regulatory approvals, statutory or charter limitations applicable.

(2) Excluding amounts that may be borrowed under the regulated companies' money pool.

(3) Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at least BBB by S&P and Baa2 by Moody's.

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower's borrowing sub-limit.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of December 31, 2010, FirstEnergy's and its subsidiaries' debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	60.6 %
FES	52.6 %
OE	54.1 %
Penn	37.7 %
CEI	57.1 %
TE	57.6 %
JCP&L	34.6 %
Met-Ed	41.5 %
Penelec	54.7 %
ATSI	48.3 %

As of December 31, 2010, FirstEnergy could issue additional debt of approximately $3.2 billion, or recognize a reduction in equity of approximately $1.7 billion, and remain within the limitations of the financial covenants required by its revolving credit facility.

The revolving credit facility does not contain provisions that either restrict the ability to borrow or accelerate repayment of outstanding advances as a result of any change in credit ratings. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2010 was 0.51% per annum for the regulated companies' money pool and 0.60% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2010, FirstEnergy's currently payable long-term debt included approximately $827 million (FES - $778 million, Met-Ed - $29 million and Penelec - $20 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy variable interest rate PCRBs were issued by the following banks as of December 31, 2010:

LOC Bank	Aggregate LOC Amount[2]	LOC Termination Date	Reimbursements of LOC Draws Due
	(In millions)		
CitiBank N.A.	$ 166	June 2014	June 2014
The Bank of Nova Scotia	178	Beginning April 2011	Multiple dates[3]
The Royal Bank of Scotland	131	June 2012	6 months
Wachovia Bank	152	March 2014	March 2014
Barclays Bank[1]	208	April 2011	30 days
Total	$ 835		

[1]Supported by 13 participating banks, with no one bank having more than 22% of the total commitment.

[2]Includes approximately $8 million of applicable interest coverage.

[3]Shorter of 6 months or LOC termination date ($49 million) and shorter of one year or LOC termination date ($129 million).

On August 20, 2010, FES completed the remarketing of $250 million of PCRBs. Of the $250 million, $235 million of PCRBs were converted from a variable interest rate to a fixed interest rate. The remaining $15 million of PCRBs continue to bear a fixed interest rate. The interest rate conversion minimizes financial risk by converting the long-term debt into a fixed rate and, as a result, reducing exposure to variable interest rates over the short-term. These remarketings included two series: $235 million of PCRBs that now bears a per-annum rate of 2.25% and is subject to mandatory purchase on June 3, 2013; and $15 million of PCRBs that now bears a per-annum rate of 1.5% and is subject to mandatory purchase on June 1, 2011.

On October 1, 2010, FES completed the refinancing and remarketing of six series of PCRBs totaling $313 million. These PCRBs were converted from a variable interest rate to a fixed long term interest rate of 3.375% per annum and are subject to mandatory purchase on July 1, 2015.

On December 3, 2010, FES completed the remarketing of four series of PCRBs totaling $153 million and Penelec completed the remarketing of $25 million PCRBs. These PCRBs were converted from a variable interest rate to fixed interest rates ranging from 2.25% to 3.75% per annum.

Long-Term Debt Capacity

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.

FirstEnergy's access to capital markets and costs of financing are influenced by the ratings of its securities. 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. 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 issued a report reaffirming the ratings and stable outlook of FirstEnergy and its subsidiaries. Fitch revised its outlook on FirstEnergy and FES from stable to negative on December 15, 2010. The following table displays FirstEnergy's, FES' and the Utilities' securities ratings as of December 31, 2010:

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**
FirstEnergy Corp.	-	-	-	BB+	Baa3	BBB
FES	-	-	-	BBB-	Baa2	BBB
OE	BBB	A3	BBB+	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	-	-	-
CEI	BBB	Baa1	BBB	BBB-	Baa3	BBB-
TE	BBB	Baa1	BBB	-	-	-
JCP&L	-	-	-	BBB-	Baa2	BBB+
Met-Ed	BBB	A3	BBB+	BBB-	Baa2	BBB
Penelec	BBB	A3	BBB+	BBB-	Baa2	BBB
ATSI	-	-	-	BBB-	Baa1	-

Changes in Cash Position

As of December 31, 2010, FirstEnergy had $1 billion of cash and cash equivalents compared to $874 million as of December 31, 2009. As of December 31, 2010 and 2009, FirstEnergy had approximately $13 million and $12 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During 2010, FirstEnergy received $850 million of cash dividends from its subsidiaries and paid $670 million in cash dividends to common shareholders.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities is provided primarily by its competitive energy services and energy delivery services businesses (see Results of Operations above). Net cash provided from operating activities was $3.1 billion in 2010, $2.5 billion in 2009 and $2.2 billion in 2008, as summarized in the following table:

Operating Cash Flows	**2010**	**2009**	**2008**
		(In millions)	
Net income	$ 760	$ 990	$ 1,339
Non-cash charges and other adjustments	2,309	2,281	1,405
Pension trust contribution	-	(500)	-
Working capital and other	7	(306)	(520)
	$ 3,076	$ 2,465	$ 2,224

The increase in non-cash charges and other adjustments is primarily due to increased impairment charges on long lived assets ($378 million) combined with higher deferred income taxes and investment tax credits ($86 million), partially offset by lower net amortization of regulatory assets of ($297 million), including the impact of CEI's $216 million regulatory asset impairment recorded during the first quarter of 2009, and reduced charges relating to debt redemptions, primarily caused by a $142 million charge relating to debt redemptions during the third quarter of 2009.

The change in working capital and other is primarily due to cash proceeds of $129 million received on the termination of fixed-for-floating interest rate swaps during the second and third quarters of 2010, changes in investment securities of $121 million, increased accrued taxes and decreased prepayments primarily related to prepaid taxes ($279 million) and changes in uncertain tax positions ($176 million), partially offset by increased accounts receivable ($252 million), decreased accrued interest ($60 million) and increased cash collateral paid to third parties ($56 million).

Cash Flows From Financing Activities

In 2010, cash used for financing activities was $983 million compared to cash provided from financing activities of $49 million in 2009. The change was primarily due to reduced long-term debt issued in 2010 compared to 2009, partially offset by reduced long-term debt redemptions and reduced payments on short-term borrowings in 2010 as compared to 2009. The following table summarizes security issuances (net of any discounts) and redemptions:

Securities Issued or Redeemed	**2010**	**2009**	**2008**
		(In millions)	
New Issues			
First mortgage bonds	$ -	$ 398	$ 592
Pollution control notes	740	940	692
Senior secured notes	350	297	-
Unsecured Notes	9	2,997	83
	$ 1,099	$ 4,632	$ 1,367
Redemptions			
First mortgage bonds	$ 32	$ 1	$ 126
Pollution control notes	741	884	698
Senior secured notes	141	217	35
Unsecured notes	101	1,508	175
	$ 1,015	$ 2,610	$ 1,034
Short-term borrowings, net	$ (378)	$ (1,246)	$ 1,494

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted primarily from property additions. Additions for the energy delivery services segment primarily represent expenditures related to transmission and distribution facilities. Capital spending by the competitive energy services segment is principally generation-related. The following table summarizes investing activities for 2010, 2009 and 2008 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)		(In millions)		
2010				
Energy delivery services	$ (745)	$ 96	$ 13	$ (636)
Competitive energy services	(1,129)	(43)	(51)	(1,223)
Other	(24)	(7)	30	(1)
Inter-Segment reconciling items	(65)	(23)	-	(88)
Total	$ (1,963)	$ 23	$ (8)	$ (1,948)
2009				
Energy delivery services	$ (750)	$ 39	$ (46)	$ (757)
Competitive energy services	(1,262)	(8)	(19)	(1,289)
Other	(149)	(3)	72	(80)
Inter-Segment reconciling items	(42)	(24)	7	(59)
Total	$ (2,203)	$ 4	$ 14	$ (2,185)
2008				
Energy delivery services	$ (839)	$ (41)	$ (17)	$ (897)
Competitive energy services	(1,835)	(14)	(56)	(1,905)
Other	(176)	106	(61)	(131)
Inter-Segment reconciling items	(38)	(12)	-	(50)
Total	$ (2,888)	$ 39	$ (134)	$ (2,983)

Net cash used for investing activities in 2010 decreased by $237 million compared to 2009. The decrease was principally due to a $240 million decrease in property additions (principally lower AQC system expenditures) and an increase in cash proceeds from the sale of assets of $96 million, partially offset by $113 million spent by FES in the customer acquisition process.

During 2011 through 2013 we anticipate average annual baseline capital expenditures of approximately $1.2 billion, exclusive of any additional opportunities or future mandated spending. This includes approximately $133 million, $300 million and $183 million in nuclear fuel expenditures for 2011, 2012 and 2013, respectively.

CONTRACTUAL OBLIGATIONS

As of December 31, 2010, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2011	2012-2013	2014-2015	Thereafter
			(In millions)		
Long-term debt	$ 13,928	$ 437	$ 995	$ 1,165	$ 11,331
Short-term borrowings	700	700	-	-	-
Interest on long-term debt[(1)]	10,978	793	1,518	1,379	7,288
Operating leases[(2)]	3,314	213	477	506	2,118
Fuel and purchased power[(3)]	16,851	2,660	4,015	3,923	6,253
Capital expenditures	1,109	340	463	306	-
Pension funding	1,076	250	74	543	209
Other[(4)]	112	31	14	14	53
Total	$ 48,068	$ 5,424	$ 7,556	$ 7,836	$ 27,252

[(1)]Interest on variable-rate debt based on rates as of December 31, 2010.
[(2)]See Note 7 to the consolidated financial statements.
[(3)]Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
[(4)]Includes amounts for capital leases (see Note 7) and contingent tax liabilities (see Note 9).

Excluded from the data shown above are estimates for the cash outlays stemming from the power purchase contracts entered into by the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. The exact amount of outlay will be determined by future customer behavior and consumption levels, but based on numerous planning assumptions management estimates an amount of $3.0 billion during 2011.

GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon either FirstEnergy or its subsidiaries' credit ratings.

As of December 31, 2010, FirstEnergy's maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 300
LOC (long-term debt) --Interest coverage[2]	2
FirstEnergy guarantee of OVEC obligations	300
Other[3]	227
	829
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	54
LOC (long-term debt) --Interest coverage[2]	3
FES' guarantee of NGC's nuclear property insurance	70
FES' guarantee of FGCO's sale and leaseback obligations	2,375
Other	2
	2,504
Surety Bonds	82
LOC (long-term debt) -- Interest coverage[2]	3
LOC (non-debt)[4][5]	339
	424
Total Guarantees and Other Assurances	$ 3,757

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $827 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $15 million for nuclear decommissioning funding assurances, $161 million supporting OE's sale and leaseback arrangement, and $39 million for railcar leases.

(4) Includes $167 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facility.

(5) Includes approximately $130 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $42 million pledged in connection with the sale and leaseback of Perry by OE.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by its subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by FirstEnergy's assets. FirstEnergy believes the likelihood is remote that such parental guarantees will increase amounts otherwise paid by FirstEnergy to meet its obligations incurred in connection with ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade to below investment grade, an acceleration or funding obligation or a "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2010, FirstEnergy's maximum exposure under these collateral provisions was $468 million, as shown below:

Collateral Provisions		**FES**		**Utilities**		**Total**
				(In millions)		
Credit rating downgrade to below investment grade [1]	$	364	$	65	$	429
Material adverse event [2]		39		-		39
Total	$	403	$	65	$	468

(1) Includes $137 million and $54 million that is also considered an acceleration of payment or funding obligation at FES and the Utilities, respectively.

(2) Includes $33 million that is also considered an acceleration of payment or funding obligation at FES.

Stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to $532 million consisting of $486 million due to a below investment grade credit rating (of which $224 million is related to an acceleration of payment or funding obligation) and $46 million due to "material adverse event" contractual clauses.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $82 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' power portfolio as of December 31, 2010, and forward prices as of that date, FES has posted collateral of $185 million. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $28 million. Depending on the volume of forward contracts and future price movements, FES could be required to post higher amounts for margining.

In connection with FES' obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

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

As noted above under Capital Resources and Liquidity, FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC have provided a guaranty of the borrowers' obligations under the $350 million syndicated two-year senior secured term loan facility entered into by Signal Peak and Global Rail. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the banks as collateral for the facility.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1.6 billion as of December 31, 2010.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices associated with electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 6 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of December 31, 2010 are summarized by contract year in the following table:

Source of Information- Fair Value by Contract Year	2011	2012	2013	2014	2015	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other external sources[2]	(331)	(157)	(52)	(36)	-	-	(576)
Prices based on models	-	-	-	-	24	110	134
Total[3]	$ (331)	$ (157)	$ (52)	$ (36)	$ 24	$ 110	$ (442)

(1) Represents futures and options traded on the New York Mercantile Exchange.

(2) Primarily represents contracts based on broker and IntercontinentalExchange quotes.

(3) Includes $335 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $16 million ($10 million net of tax) during the next 12 months.

Interest Rate Swap Agreements – Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivatives were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of December 31, 2010, no fixed-for-floating interest rate swap agreements were outstanding.

Total unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $124 million ($80 million net of tax) as of December 31, 2010. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled $12 million during 2010.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 7 to the consolidated financial statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2011	2012	2013	2014	2015	There-after	Total	Fair Value
				(In millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 80	$ 90	$ 101	$ 110	$ 76	$ 1,755	$ 2,212	$ 2,304
Average interest rate	8.4 %	8 %	8 %	8 %	8.1 %	5.7 %	6.2 %	
Liabilities								
Long-term Debt:								
Fixed rate	$ 437	$ 94	$ 551	$ 536	$ 629	$ 10,504	$ 12,751	$ 13,668
Average interest rate	5.7 %	7.8 %	5.8 %	5.4 %	5.2 %	6.3 %	6.1 %	
Variable rate		$ 350				$ 827	$ 1,177	$ 1,177
Average interest rate		2.5 %				0.3 %	1 %	
Short-term Borrowings:	$ 700						$ 700	$ 700
Average interest rate	0.7 %						0.7 %	

Equity Price Risk

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plan provides defined benefits based on years of service and compensation levels. FirstEnergy also provides health care benefits (which include certain employee contributions, deductibles and co-payments) upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. As of December 31, 2010, approximately 28% of the pension plan assets are invested in equity securities, 50% invested in fixed income securities, 11% invested in absolute return strategies, 6% invested in real estate, 4% invested in private equity and 1% invested in cash. The plan is 83% funded on an accumulated benefit obligation basis as of December 31, 2010. A decline in the value of FirstEnergy's pension plan assets could result in additional funding requirements. FirstEnergy intends to voluntarily contribute $250 million to its pension plan in 2011.

Nuclear decommissioning trust funds have been established to satisfy NGC's and the Utilities' nuclear decommissioning obligations. As of December 31, 2010, approximately 73% of the funds were invested in fixed income securities, 17% of the funds were invested in equity securities and 10% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,454 million, $337 million and $189 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $34 million reduction in fair value as of December 31, 2010. The decommissioning trusts of JCP&L and the Pennsylvania Companies are subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts as other-than-temporary impairments. A decline in the value of FirstEnergy's nuclear decommissioning trusts or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2010, $4 million was contributed to the OE and TE nuclear decommissioning trusts to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees, and $6 million was contributed to the JCP&L and Pennsylvania nuclear decommissioning trusts to comply with regulatory requirements. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

CREDIT RISK

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. FirstEnergy engages in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy aggressively manages the quality of its portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of December 31, 2010, the largest credit concentration was with J.P. Morgan Chase & Co., which is currently rated investment grade, representing 10.9% of FirstEnergy's total approved credit risk composed of 3.3% for FES, 2.2% for JCP&L, 2.7% for Met-Ed and a combined 2.7% for OE, TE and CEI.

REGULATORY MATTERS

Regulatory assets that do not earn a current return totaled approximately $215 million as of December 31, 2010 (JCP&L - $38 million, Met-Ed - $131 million, Penelec - $12 million, CEI - $16 million and OE - $18 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) are expected to be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec.

FirstEnergy and the Utilities prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred or accrued costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the recovery of costs or accrued liabilities that have been deferred because it is probable such amounts will be returned to customers through future regulated rates. The following table provides the balance of regulatory assets by Company as of December 31, 2010 and 2009, and changes during 2010:

Regulatory Assets	December 31, 2010	December 31, 2009	Increase (Decrease)
		(In millions)	
OE	$ 400	$ 465	$ (65)
CEI	370	546	(176)
TE	72	70	2
JCP&L	513	888	(375)
Met-Ed	296	357	(61)
Penelec	163	9	154
Other	12	21	(9)
Total	$ 1,826	$ 2,356	$ (530)

The following table provides information about the composition of regulatory assets as of December 31, 2010 and 2009 and the changes during 2010:

Regulatory Assets by Source	December 31, 2010	December 31, 2009	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 770	$ 1,100	$ (330)
Customer shopping incentives	-	154	(154)
Customer receivables for future income taxes	326	329	(3)
Loss on reacquired debt	48	51	(3)
Employee postretirement benefits	16	23	(7)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)	(162)	(22)
Asset removal costs	(237)	(231)	(6)
MISO/PJM transmission costs	184	148	36
Deferred generation costs	386	369	17
Distribution costs	426	482	(56)
Other	91	93	(2)
Total	$ 1,826	$ 2,356	$ (530)

Ohio

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.

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

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

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.

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.

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.

Reliability Initiatives

Federally-enforceable 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 these reliability standards 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 implemented and enforced by the Reliability*First* Corporation.

FirstEnergy believes that it generally 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, 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.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to Reliability*First* a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, Reliability*First* issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to Reliability*First* on September 27, 2010. At this time, FirstEnergy is unable to predict the outcome of this investigation.

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.

OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court's decision decertifying the class. Plaintiffs have filed, and JCP&L has opposed, a motion for leave to appeal to the New Jersey Supreme Court. JCP&L is waiting for the Court's decision.

Litigation Relating to the Proposed Allegheny Merger

In connection with the proposed merger (Note 22), purported shareholders of Allegheny have filed putative shareholder class action and/or derivative lawsuits against Allegheny and its directors and certain officers, referred to as the Allegheny Energy defendants, FirstEnergy and Merger Sub. Four putative class action and derivative lawsuits were filed in the Circuit Court for Baltimore City, Maryland (Maryland Court). One was withdrawn. The Maryland Court has consolidated the remaining three cases under the caption: In re Allegheny Energy Shareholder and Derivative Litigation, C.A. No. 24-C-10-1301. Three shareholder lawsuits were filed in the Court of Common Pleas of Westmoreland County, Pennsylvania and the court has consolidated these actions under the caption: In re Allegheny Energy, Inc. Shareholder Class and Derivative, Litigation, Lead Case No. 1101 of 2010. One putative shareholder class action was filed in the U.S. District Court for the Western District of Pennsylvania and is captioned Louisiana Municipal Police Employees' Retirement System v. Evanson, et al., C.A. No. 10-319 NBF. In summary, the lawsuits allege, among other things, that the Allegheny Energy directors breached their fiduciary duties by approving the merger agreement, and that Allegheny, FirstEnergy and Merger Sub aided and abetted in these alleged breaches of fiduciary duty. The complaints seek, among other things, jury trials, money damages and injunctive relief. While FirstEnergy believes the lawsuits are without merit and has defended vigorously against the claims, in order to avoid the costs associated with the litigation, the defendants have agreed to the terms of a disclosure-based settlement of all these shareholder lawsuits and have reached agreement with counsel for all of the plaintiffs concerning fee applications. Under the terms of the settlement, no payments are being made by FirstEnergy or Merger Sub. A formal stipulation of settlement was filed with the Maryland Court on October 18, 2010 and it was approved and became final on January 12, 2011. The separate Pennsylvania federal and state proceedings were dismissed on January 14, 2011 and January 18, 2011, respectively. The above shareholder actions have been fully and finally resolved.

Nuclear Plant Matters

During a planned refueling outage that began on February 28, 2010, FENOC conducted a non destructive examination and testing of the CRDM nozzles of the Davis-Besse reactor pressure vessel head. FENOC identified flaws in CRDM nozzles that required modification. The NRC was notified of these findings, along with federal, state and local officials. On March 17, 2010, the NRC sent a special inspection team to Davis-Besse to assess the adequacy of FENOC's identification, analyses and resolution of the CRDM nozzle flaws and to ensure acceptable modifications were made prior to placing the RPV head back in service. After successfully completing the modifications, FENOC committed to take a number of corrective actions including strengthening leakage monitoring procedures and shutting Davis-Besse down no later than October 1, 2011, to replace the reactor pressure vessel head with nozzles made of material less susceptible to primary water stress corrosion cracking, further enhancing the safe and reliable operations of the plant. On June 29, 2010, FENOC returned Davis-Besse to service. On September 9, 2010, the NRC held a public exit meeting describing the results of the NRC special inspection team inspection of FENOC's identification of the CRDM nozzles with flaws and the modifications to those nozzles. On October 22, 2010, the NRC issued its final report of the special inspection. The report contained three findings characterized as very low safety significance that were promptly corrected prior to plant operation.

On April 5, 2010, the Union of Concerned Scientists (UCS) requested that the NRC issue a Show Cause Order, or otherwise delay the restart of the Davis-Besse Nuclear Power Station until the NRC determines that adequate protection standards have been met and reasonable assurance exists that these standards will continue to be met after the plant's operation is resumed. By a letter dated July 13, 2010, the NRC denied UCS's request for immediate action because "the NRC has conducted rigorous and independent assessments of returning the Davis-Besse reactor vessel head to service and its continued operation, and determined that it was safe for the plant to restart." The UCS petition was referred to a petition manager for further review. What additional actions, if any, that the NRC takes in response to the UCS request have not been determined.

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 issued guidance anticipating an increase in low-level radioactive waste disposal costs associated 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.

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.

Ohio Legal Matters

On February 16, 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount was approved by the PUCO. On March 18, 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described below.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of FirstEnergy assets are subject to specific risks and uncertainties and are regularly reviewed for impairment. FirstEnergy's more significant accounting policies are described below.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class.

Regulatory Accounting

FirstEnergy's energy delivery services segment is subject to regulation that sets the prices (rates) the Utilities are permitted to charge customers based on costs that the regulatory agencies determine the Utilities are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Pension and Other Postretirement Benefits Accounting

FirstEnergy's reported costs of providing noncontributory qualified and non-qualified defined pension benefits and OPEB benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions FirstEnergy makes to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with GAAP, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. GAAP delays recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants' experience.

FirstEnergy recognizes the overfunded or underfunded status of the defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans at December 31, 2010 was $1.7 billion. FirstEnergy voluntarily intends to contribute $250 million to its pension plan in 2011.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed discount rates for pension were 5.50%, 6.00% and 7.00% for December 31, 2010, 2009 and 2008, respectively. The assumed discount rates for OPEB were 5.00%, 5.75% and 7.0% as of December 31, 2010, 2009 and 2008, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2010, FirstEnergy's qualified pension and OPEB plan assets earned $492 million or 10.1% compared to amounts earned of $570 million or 13.6% in 2009. The qualified pension and OPEB costs in 2010 and 2009 were computed using an assumed 8.5% and 9.0% rate of return, respectively, on plan assets which generated $397 million and $379 million of expected returns on plan assets, respectively. The expected return of pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension and OPEB cost, respectively.

FirstEnergy's qualified and non-qualified pension and OPEB net periodic benefit cost was $138 million in 2010 compared to $197 million in 2009 and credits of $116 million in 2008. FirstEnergy expects the 2011 qualified and non-qualified pension and OPEB costs (including amounts capitalized) to be $103 million.

On June 2, 2009, FirstEnergy amended the health care benefits plan for all employees and retirees eligible that participate in that plan. The amendment, which reduces future health care coverage subsidies paid by FirstEnergy on behalf of participants, triggered a remeasurement of FirstEnergy's other postretirement benefit plans as of May 31, 2009. On September 2, 2009, the Utilities and ATSI made a combined $500 million voluntary contribution to their qualified pension plan. Due to the significance of the voluntary contribution, FirstEnergy elected to remeasure the qualified pension plan as of August 31, 2009. In the third quarter of 2009, FirstEnergy also incurred a $13 million net postretirement benefit cost (including amounts capitalized) related to a liability created by the VERO offered by FirstEnergy to qualified employees. The special termination benefits of the VERO included additional health care coverage subsidies paid by FirstEnergy to those qualified employees who elected to retire. A total of 715 employees accepted the VERO.

Health care cost trends continue to increase and will affect future OPEB costs. The 2010 composite health care trend rate assumptions were approximately 8-9%, compared to 8.5-10% in 2009, gradually decreasing to 5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$ 13	$ 1	$ 14
Long-term return on assets	Decrease by 0.25%	$ 12	$ 1	$ 13
Health care trend rate	Increase by 1%	N/A	$ 4	$ 4

Emission Allowances

FirstEnergy holds emission allowances for SO_2 and NO_X in order to comply with programs implemented by the EPA designed to regulate emissions of SO_2 and NO_X produced by power plants. Emission allowances are either granted by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. FirstEnergy recognizes emission allowance costs as fuel expense during the periods that emissions are produced by generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses.

Long-Lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of a long-lived asset is measured by comparing the asset's carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted future cash flows of the long-lived asset, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of FirstEnergy's nuclear power plants and future remediation of other environmental liabilities associated with long-lived assets. The ARO liability represents an estimate of the fair value of the current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license, settlement based on an extended license term and expected remediation dates.

Income Taxes

We record income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

See Note 16 to the consolidated financial statements for discussion of new accounting pronouncements.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2010 consolidated financial statements.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2010.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2010. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 134.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common stockholders' equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 16, 2011

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	For the Years Ended December 31, 2010	2009	2008
REVENUES:			
Electric utilities	$ 9,815	$ 11,139	$ 12,061
Unregulated businesses	3,524	1,834	1,566
Total revenues*	13,339	12,973	13,627
EXPENSES:			
Fuel	1,432	1,153	1,340
Purchased power	4,624	4,730	4,291
Other operating expenses	2,850	2,697	3,045
Provision for depreciation	746	736	677
Amortization of regulatory assets	722	1,155	1,053
Deferral of regulatory assets	-	(136)	(316)
General taxes	776	753	778
Impairment of long-lived assets	384	6	-
Total expenses	11,534	11,094	10,868
OPERATING INCOME	1,805	1,879	2,759
OTHER INCOME (EXPENSE):			
Investment income	117	204	59
Interest expense	(845)	(978)	(754)
Capitalized interest	165	130	52
Total other expense	(563)	(644)	(643)
INCOME BEFORE INCOME TAXES	1,242	1,235	2,116
INCOME TAXES	482	245	777
NET INCOME	760	990	1,339
Loss attributable to noncontrolling interest	(24)	(16)	(3)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 784	$ 1,006	$ 1,342
BASIC EARNINGS PER SHARE OF COMMON STOCK	$ 2.58	$ 3.31	$ 4.41
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	304	304	304
DILUTED EARNINGS PER SHARE OF COMMON STOCK	$ 2.57	$ 3.29	$ 4.38
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	305	306	307

* Includes $428 million, $395 million and $432 million of excise tax collections in 2010, 2009 and 2008, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,019	$ 874
Receivables-		
Customers, net of allowance for uncollectible accounts of $36 in 2010 and $33 in 2009	1,392	1,244
Other, net of allowance for uncollectible accounts of $8 in 2010 and $7 in 2009	176	153
Materials and supplies, at average cost	638	647
Prepaid taxes	199	248
Other	274	154
	3,698	3,320
PROPERTY, PLANT AND EQUIPMENT:		
In service	29,451	27,826
Less - Accumulated provision for depreciation	11,180	11,397
	18,271	16,429
Construction work in progress	1,517	2,735
	19,788	19,164
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,973	1,859
Investments in lease obligation bonds	476	543
Other	553	621
	3,002	3,023
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,575	5,575
Regulatory assets	1,826	2,356
Power purchase contract asset	122	200
Other	794	666
	8,317	8,797
	$ 34,805	$ 34,304
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,486	$ 1,834
Short-term borrowings	700	1,081
Accounts payable	872	829
Accrued taxes	326	314
Accrued compensation and benefits	315	293
Derivatives	266	126
Other	733	711
	4,698	5,188
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 375,000,000 shares- 304,835,407 shares outstanding	31	31
Other paid-in capital	5,444	5,448
Accumulated other comprehensive loss	(1,539)	(1,415)
Retained earnings	4,609	4,495
Total common stockholders' equity	8,545	8,559
Noncontrolling interest	(32)	(2)
Total equity	8,513	8,557
Long-term debt and other long-term obligations	12,579	12,008
	21,092	20,565
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,879	2,468
Retirement benefits	1,868	1,534
Asset retirement obligations	1,407	1,425
Deferred gain on sale and leaseback transaction	959	993
Power purchase contract liability	466	643
Lease market valuation liability	217	262
Other	1,219	1,226
	9,015	8,551
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 7 and 14)		
	$ 34,805	$ 34,304

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(Dollars in millions)	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
Balance, January 1, 2008		304,835,407	$ 31	$ 5,509	$ (50)	$ 3,487
Earnings available to FirstEnergy Corp.	$ 1,342					1,342
Unrealized loss on derivative hedges, net of $16 million of income tax benefits	(28)				(28)	
Change in unrealized gain on investments, net of $86 million of income tax benefits	(146)				(146)	
Pension and other postretirement benefits, net of $697 million of income tax benefits (Note 3)	(1,156)				(1,156)	
Comprehensive income	$ 12					
Stock options exercised				(36)		
Restricted stock units				(1)		
Stock-based compensation				1		
Cash dividends declared on common stock						(670)
Balance, December 31, 2008		304,835,407	31	5,473	(1,380)	4,159
Earnings available to FirstEnergy Corp.	$ 1,006					1,006
Unrealized gain on derivative hedges, net of $24 million of income taxes	27				27	
Change in unrealized gain on investments, net of $31 million of income tax benefits	(43)				(43)	
Pension and other postretirement benefits, net of $34 million of income taxes (Note 3)	(19)				(19)	
Comprehensive income	$ 971					
Stock options exercised				(3)		
Restricted stock units				7		
Stock-based compensation				1		
Acquisition adjustment of non-controlling interest (Note 8)				(30)		
Cash dividends declared on common stock						(670)
Balance, December 31, 2009		304,835,407	31	5,448	(1,415)	4,495
Earnings available to FirstEnergy Corp.	$ 784					784
Unrealized gain on derivative hedges, net of $14 million of income taxes	22				22	
Unrealized gain on investments, net of $3 million of income taxes	5				5	
Pension and other postretirement benefits, net of $107 million of income tax benefits (Note 3)	(151)				(151)	
Comprehensive income	$ 660					
Stock options exercised				(2)		
Restricted stock units				(3)		
Stock-based compensation				1		
Cash dividends declared on common stock						(670)
Balance, December 31, 2010		304,835,407	$ 31	$ 5,444	$ (1,539)	$ 4,609

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	As of December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 760	$ 990	$ 1,339
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	746	736	677
Amortization of regulatory assets	722	1,155	1,053
Deferral of regulatory assets	-	(136)	(316)
Nuclear fuel and lease amortization	168	128	112
Deferred purchased power and other costs	(254)	(338)	(226)
Deferred income taxes and investment tax credits, net	470	384	366
Impairment of long-lived assets (Note 19)	384	6	-
Investment impairment (Note 2(E))	33	62	123
Deferred rents and lease market valuation liability	(54)	(52)	(95)
Stock based compensation	(1)	20	(64)
Accrued compensation and retirement benefits	89	22	(140)
Gain on asset sales	(2)	(27)	(72)
Electric service prepayment programs	-	(10)	(77)
Cash collateral, net	(26)	30	(31)
Gain on sales of investment securities held in trusts, net	(55)	(176)	(63)
Loss on debt redemption	5	146	-
Interest rate swap transactions	129	-	-
Commodity derivative transactions, net (Note 6)	(81)	229	5
Pension trust contributions	-	(500)	-
Uncertain tax positions	(34)	(210)	(5)
Acquisition of supply requirements	-	(93)	-
Decrease (increase) in operating assets-			
Receivables	(177)	75	(29)
Materials and supplies	2	(11)	(52)
Prepayments and other current assets	100	(19)	(263)
Increase (decrease) in operating liabilities-			
Accounts payable	43	50	10
Accrued taxes	57	(103)	(39)
Accrued interest	7	67	4
Other	45	40	7
Net cash provided from operating activities	$ 3,076	$ 2,465	$ 2,224
CASH FLOWS FROM FINANCING ACTIVITIES:			
New financing-			
Long-term debt	1,099	4,632	1,367
Short-term borrowings, net	-	-	1,494
Redemptions and repayments-			
Long-term debt	(1,015)	(2,610)	(1,034)
Short-term borrowings, net	(378)	(1,246)	-
Common stock dividend payments	(670)	(670)	(671)
Other	(19)	(57)	19
Net cash provided from (used for) financing activities	$ (983)	$ 49	$ 1,175
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,963)	(2,203)	(2,888)
Proceeds from asset sales	117	21	72
Sales of investment securities held in trusts	3,172	2,229	1,656
Purchases of investment securities held in trusts	(3,219)	(2,306)	(1,749)
Customer acquisition costs	(113)	-	-
Cash investments (Note 5)	66	60	60
Other	(8)	14	(134)
Net cash used for investing activities	$ (1,948)	$ (2,185)	$ (2,983)
Net increase in cash and cash equivalents	145	329	416
Cash and cash equivalents at beginning of year	874	545	129
Cash and cash equivalents at end of year	$ 1,019	$ 874	$ 545
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year-			
Interest (net of amounts capitalized)	$ 662	$ 718	$ 667
Income taxes (benefits)	$ (42)	$ 173	$ 685

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

COMBINED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, FES and its subsidiaries FGCO and NGC and FESC.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the PUCO, PPUC and NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. In preparing the financial statements, FirstEnergy and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation unless otherwise prescribed by GAAP (see Note 15). FirstEnergy consolidates a VIE (see Note 8) when it is determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income. These footnotes combine results of FE, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec.

Certain prior year amounts have been reclassified to conform to the current year presentation. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

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.

Regulatory assets on the Balance Sheets are comprised of the following:

Regulatory Assets	FE	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
December 31, 2010							
Regulatory transition costs	$ 770	$ -	$ -	$ -	$ 591	$ 131	$ 43
Customer shopping incentives	-	-	-	-	-	-	-
Customer receivables for future income taxes	326	50	2	1	30	113	130
Loss (gain) on reacquired debt	48	17	1	(3)	21	6	6
Employee postretirement benefits	16	-	3	2	7	4	-
Nuclear decommissioning, decontamination and spent fuel disposal costs	(184)	-	-	-	(31)	(92)	(61)
Asset removal costs	(237)	(24)	(47)	(19)	(147)	-	-
MISO/PJM transmission costs	184	(1)	-	-	-	131	52
Deferred generation costs	386	125	226	35	-	-	-
Distribution costs	426	216	155	55	-	-	-
Other	91	17	30	1	42	3	(7)
Total	$ 1,826	$ 400	$ 370	$ 72	$ 513	$ 296	$ 163
December 31, 2009							
Regulatory transition costs	$ 1,100	$ 73	$ 8	$ 8	$ 965	$ 116	$ (70)
Customer shopping incentives	154	-	154	-	-	-	-
Customer receivables for future income taxes	329	58	3	1	31	114	122
Loss (gain) on reacquired debt	51	18	1	(3)	22	8	5
Employee postretirement benefits	23	-	5	2	10	6	-
Nuclear decommissioning, decontamination and spent fuel disposal costs	(162)	-	-	-	(22)	(83)	(57)
Asset removal costs	(231)	(23)	(43)	(17)	(148)	-	-
MISO/PJM transmission costs	148	(15)	(15)	(3)	-	187	(6)
Deferred generation costs	369	115	222	32	-	-	-
Distribution costs	482	230	197	55	-	-	-
Other	93	9	14	(5)	30	9	15
Total	$ 2,356	$ 465	$ 546	$ 70	$ 888	$ 357	$ 9

Regulatory assets that do not earn a current return totaled approximately $215 million as of December 31, 2010 (JCP&L - $38 million, Met-Ed - $131 million, Penelec - $12 million, OE - $18 million and, CEI - $16 million). Regulatory assets of JCP&L, Met-Ed and Penelec not earning a current return are primarily for certain regulatory transition costs and employee postretirement benefits and will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec. Regulatory assets of OE and CEI not earning a current return primarily relate to the deferral of certain purchased power costs for which the means of recovery as not yet been established by the PUCO.

Transition Cost Amortization

JCP&L's and Met-Ed's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $164 million for JCP&L (recovered through NGC revenues) and $128 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (see Note 10).

(B) REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Utilities' retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include distribution and retail electric sales to residential, commercial and industrial customers for the Utilities and retail and wholesale sales to customers for FES. There was no material concentration of receivables as of December 31, 2010 and 2009 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2010 and 2009 are shown below.

Customer Receivables	FE	FES	OE	CEI	TE[1]	JCP&L	Met-Ed	Penelec
				(In millions)				
December 31, 2010								
Billed	$ 752	$ 196	$ 81	$ 95	$ -	$ 178	$ 101	$ 82
Unbilled	640	170	96	89	-	145	78	67
Total	$ 1,392	$ 366	$ 177	$ 184	$ -	$ 323	$ 179	$ 149
December 31, 2009								
Billed	$ 725	$ 109	$ 101	$ 114	$ 1	$ 183	$ 110	$ 88
Unbilled	519	86	108	95	-	118	61	51
Total	$ 1,244	$ 195	$ 209	$ 209	$ 1	$ 301	$ 171	$ 139

[1] See Note 13 for a discussion of TE's accounts receivable financing arrangement with Centerior Funding Corporation.

(C) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2010	2009	2008
	(In millions, except per share amounts)		
Earnings available to FirstEnergy Corp.	$ 784	$ 1,006	$ 1,342
Weighted average number of basic shares outstanding	304	304	304
Assumed exercise of dilutive stock options and awards	1	2	3
Weighted average number of diluted shares outstanding	305	306	307
Basic earnings per share of common stock	$ 2.58	$ 3.31	$ 4.41
Diluted earnings per share of common stock	$ 2.57	$ 3.29	$ 4.38

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which are adjusted to fair value), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. Property, plant and equipment balances as of December 31, 2010 and 2009 were as follows:

	December 31, 2010			December 31, 2009		
Property, Plant and Equipment	Unregulated	Regulated	Total	Unregulated	Regulated	Total
			(In millions)			
In service	$ 11,952	$ 17,499	$ 29,451	$ 10,935	$ 16,891	$ 27,826
Less accumulated depreciation	(4,229)	(6,951)	(11,180)	(4,699)	(6,698)	(11,397)
Net plant in service	$ 7,723	$ 10,548	$ 18,271	$ 6,236	$ 10,193	$ 16,429

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2010, 2009 and 2008 are shown in the following table:

	Annual Composite Depreciation Rate		
	2010	2009	2008
OE	2.9 %	3.1%	3.1%
CEI	3.2	3.3	3.5
TE	3.3	3.3	3.6
Penn	2.2	2.4	2.4
JCP&L	2.4	2.4	2.3
Met-Ed	2.5	2.5	2.3
Penelec	2.5	2.6	2.5
FGCO	4.0	4.6	4.7
NGC	3.1	3.0	2.8

Asset Retirement Obligations

FirstEnergy recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FirstEnergy's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset, as described further in Note 12.

(E) ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such an asset may not be recoverable. The recoverability of the long-lived asset is measured by comparing the long-lived asset's carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted future cash flows of the long-lived asset, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Impairments of long-lived assets recognized for the year ended December 31, 2010, are described further in Note 19.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Impairment is indicated and a loss is recognized if the implied fair value of a reporting unit's goodwill is less than the carrying value of its goodwill.

FirstEnergy's goodwill primarily relates to its energy delivery services segment. FirstEnergy's aggregated reporting units are consistent with its operating segments -- energy delivery services and competitive energy. Goodwill is allocated to these operating segments based on the original purchase price allocation for acquisitions within the various reporting units. The goodwill allocated to competitive energy is insignificant to that segment and to FirstEnergy.

Annual impairment testing is conducted during the third quarter of each year and for 2010, 2009 and 2008 the analysis indicated no impairment of goodwill. For purposes of annual testing the estimated fair values of energy delivery services and the utilities were determined using a discounted cash flow approach.

The discounted cash flow model of the reporting units, which are aggregated into operating segments, is based on the forecasted operating cash flow for the current year, projected operating cash flows for the next five years (determined using forecasted amounts as well as an estimated growth rate) and a terminal value beyond five years. Discounted cash flows consist of the operating cash flows for each reporting unit less an estimate for capital expenditures. The key assumptions incorporated in the discounted cash flow approach include growth rates, projected operating income, changes in working capital, projected capital expenditures, planned funding of pension plans, anticipated funding of nuclear decommissioning trusts, expected results of future rate proceedings and a discount rate equal to the assumed long term cost of capital. Cash flows may be adjusted to exclude certain non-recurring or unusual items. Reporting unit income, which excludes non-recurring or unusual items, was the starting point for determining operating cash flow and there were no non-recurring or unusual items excluded from the calculations of operating cash flow in any of the periods included in the determination of fair value.

Unanticipated changes in assumptions could have a significant effect on FirstEnergy's evaluation of goodwill. At the time of annual impairment testing, fair value would have to have declined in excess of 52% for energy delivery services to indicate a potential goodwill impairment. Fair value would have to have declined more than 26% for CEI, 64% for TE, 38% for JCP&L, 56% for Met-Ed and 57% for Penelec to indicate potential goodwill impairment.

A summary of the changes in goodwill for the three years ended December 31, 2010 is shown below by operating segment, which represent aggregated reporting units (see Note 15):

Goodwill	**Energy Delivery Services**	**Competitive Energy Services**	**Consolidated**
		(In millions)	
Balance as of December 31, 2007	$ 5,583	$ 24	$ 5,607
Adjustments related to GPU acquisitions	(32)	-	(32)
Balance as of December 31, 2008, 2009 and 2010	$ 5,551	$ 24	$ 5,575

A summary of the changes in FES' and the Utilities' goodwill for the three years ended December 31, 2010 is shown below.

Goodwill	**FES**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
			(In millions)			
Balance as of December, 31 2007	$ 24	$ 1,689	$ 501	$ 1,826	$ 424	$ 778
Adjustments related to GPU acquisition	-	-	-	(15)	(8)	(9)
Balance as of December, 31 2008, 2009 and 2010	$ 24	$ 1,689	$ 501	$ 1,811	$ 416	$ 769

FirstEnergy, FES and the Utilities, with the exception of Met-Ed, have no accumulated impairment charge as of December 31, 2010. Met-Ed has an accumulated impairment charge of $355 million, which was recorded in 2006.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. Investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the investment is written down to fair value. FirstEnergy recognizes in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. In 2010, 2009 and 2008, FirstEnergy recognized $33 million, $62 million and $123 million, respectively, of other-than-temporary impairments. The fair values of FirstEnergy's investments are disclosed in Note 5(B).

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with stockholders and adjustments relating to noncontrolling interests. Accumulated other comprehensive income (loss), net of tax, included on FE's, FES' and the Utilities' Consolidated Balance Sheets as of December 31, 2010 and 2009, is comprised of the following:

Accumulated Other Comprehensive Income (Loss)	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Net liability for unfunded retirement benefits	$ (1,492)	$ (127)	$ (180)	$ (153)	$ (49)	$ (253)	$ (141)	$ (164)
Unrealized gain on investments	7	6	1	-	-	-	-	-
Unrealized gain (loss) on derivative hedges	(54)	1	-	-	-	(1)	(1)	-
AOCL Balance, December 31, 2010	$ (1,539)	$ (120)	$ (179)	$ (153)	$ (49)	$ (254)	$ (142)	$ (164)
Net liability for unfunded retirement benefits	$ (1,341)	$ (91)	$ (164)	$ (138)	$ (50)	$ (242)	$ (143)	$ (162)
Unrealized gain on investments	2	2	-	-	-	-	-	-
Unrealized loss on derivative hedges	(76)	(14)	-	-	-	(1)	(1)	-
AOCL Balance, December 31, 2009	$ (1,415)	$ (103)	$ (164)	$ (138)	$ (50)	$ (243)	$ (144)	$ (162)

Other comprehensive income (loss) reclassified to net income during the three years ended December 31, 2010, 2009 and 2008 was as follows:

2010	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Pension and other postretirement benefits	$ (67)	$ (3)	$ 1	$ (13)	$ (3)	$ (16)	$ (9)	$ (7)
Gain on investments	54	50	2	-	2	-	-	-
Loss on derivative hedges	(35)	(24)	-	-	-	-	-	-
	(48)	23	3	(13)	(1)	(16)	(9)	(7)
Income taxes (benefits) related to reclassification to net income	(19)	8	1	(5)	-	(6)	(4)	(3)
Reclassification to net income	$ (29)	$ 15	$ 2	$ (8)	$ (1)	$ (10)	$ (5)	$ (4)
2009								
Pension and other postretirement benefits	$ (78)	$ (3)	$ (5)	$ (11)	$ (2)	$ (18)	$ (11)	$ (5)
Gain on investments	157	139	10	-	7	-	-	-
Loss on derivative hedges	(67)	(27)	-	-	-	-	-	-
	12	109	5	(11)	5	(18)	(11)	(5)
Income taxes (benefits) related to reclassification to net income	4	41	2	(4)	2	(8)	(5)	(2)
Reclassification to net income	$ 8	$ 68	$ 3	$ (7)	$ 3	$ (10)	$ (6)	$ (3)
2008								
Pension and other postretirement benefits	$ 80	$ 7	$ 16	$ 1	$ -	$ 14	$ 9	$ 14
Gain on investments	40	31	9	-	1	-	-	-
Loss on derivative hedges	(19)	(3)	-	-	-	-	-	-
	101	35	25	1	1	14	9	14
Income taxes related to reclassification to net income	41	14	10	-	-	6	4	6
Reclassification to net income	$ 60	$ 21	$ 15	$ 1	$ 1	$ 8	$ 5	$ 8

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. On September 2, 2009, the Utilities and ATSI made a combined $500 million voluntary contribution to their qualified pension plan. Due to the significance of the voluntary contribution, FirstEnergy elected to remeasure its qualified pension plan as of August 31, 2009. FirstEnergy intends to voluntarily contribute $250 million to its pension plan in 2011.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2008, FirstEnergy amended the OPEB plan effective in 2010 to limit the monthly contribution for pre-1990 retirees. On June 2, 2009, FirstEnergy amended its health care benefits plan for all employees and retirees eligible to participate in that plan. The amendment, which reduces future health care coverage subsidies paid by FirstEnergy on behalf of participants, triggered a remeasurement of FirstEnergy's other postretirement benefit plans as of May 31, 2009. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

In the third quarter of 2009, FirstEnergy incurred a $13 million net postretirement benefit cost (including amounts capitalized) related to a liability created by the VERO offered by FirstEnergy to qualified employees. The special termination benefits of the VERO included additional health care coverage subsidies paid by FirstEnergy to those qualified employees who elected to retire. A total of 715 employees accepted the VERO.

Obligations and Funded Status As of December 31	Pension Benefits 2010	Pension Benefits 2009	Other Benefits 2010	Other Benefits 2009
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 5,392	$ 4,700	$ 823	$ 1,189
Service cost	99	91	10	12
Interest cost	314	317	45	64
Plan participants' contributions	-	-	30	29
Plan amendments	16	6	-	(408)
Special termination benefits	-	-	-	13
Medicare retiree drug subsidy	-	-	7	20
Actuarial (gain) loss	343	648	56	23
Benefits paid	(306)	(370)	(110)	(119)
Benefit obligation as of December 31	$ 5,858	$ 5,392	$ 861	$ 823
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,399	$ 3,752	$ 467	$ 440
Actual return on plan assets	440	508	52	62
Company contributions	11	509	59	55
Plan participants' contributions	-	-	30	29
Benefits paid	(306)	(370)	(110)	(119)
Fair value of plan assets as of December 31	$ 4,544	$ 4,399	$ 498	$ 467
Funded Status				
Qualified plan	$ (1,076)	$ (787)		
Non-qualified plans	(238)	(206)		
Funded Status	$ (1,314)	$ (993)	$ (363)	$ (356)
Accumulated benefit obligation	**$ 5,469**	**$ 5,036**		
Amounts Recognized on the Balance Sheet				
Current liabilities	$ (11)	$ (10)	$ -	$ -
Noncurrent liabilities	(1,303)	(983)	(363)	(356)
Net liability as of December 31	$ (1,314)	$ (993)	$ (363)	$ (356)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 76	$ 67	$ (952)	$ (1,145)
Actuarial loss	2,554	2,486	718	756
Net amount recognized	$ 2,630	$ 2,553	$ (234)	$ (389)
Assumptions Used to Determine Benefit Obligations as of December 31				
Discount rate	5.50 %	6.00 %	5.00 %	5.75 %
Rate of compensation increase	5.20 %	5.20 %		
Allocation of Plan Assets As of December 31				
Equity securities	28 %	39 %	47 %	51 %
Bonds	50	49	45	46
Absolute return strategies	11	-	3	-
Real estate	6	6	2	1
Private equities	4	5	1	1
Cash	1	1	2	1
Total	100 %	100 %	100 %	100 %

Estimated 2011 Amortization of Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 14	$ (193)
Actuarial loss	$ 194	$ 57

Components of Net Periodic Benefit Costs	Pension Benefits 2010	2009	2008	Other Benefits 2010	2009	2008
			(In millions)			
Service cost	$ 99	$ 91	$ 87	$ 10	$ 12	$ 19
Interest cost	314	317	299	45	64	74
Expected return on plan assets	(361)	(343)	(463)	(36)	(36)	(51)
Amortization of prior service cost	13	13	13	(193)	(175)	(149)
Amortization of net actuarial loss	187	179	8	60	61	47
Net periodic cost	$ 252	$ 257	$ (56)	$ (114)	$ (74)	$ (60)

FES' and the Utilities' shares of the net pension and OPEB asset (liability) as of December 31, 2010 and 2009 are as follows:

Net Pension and OPEB Asset (Liability)	Pension Benefits 2010	2009	Other Benefits 2010	2009
		(In millions)		
FES	$ (488)	$ (361)	$ (36)	$ (19)
OE	29	30	(66)	(74)
CEI	(22)	(13)	(62)	(59)
TE	(21)	(15)	(46)	(47)
JCP&L	(106)	(77)	(70)	(56)
Met-Ed	(6)	6	(19)	(28)
Penelec	(99)	(79)	(85)	(84)

FES' and the Utilities' shares of the net periodic pension and OPEB costs for the three years ended December 31, 2010 are as follows:

Net Periodic Pension and OPEB Costs	Pension Benefits 2010	2009	2008	Other Benefits 2010	2009	2008
			(In millions)			
FES	$ 84	$ 71	$ 15	$ (27)	$ (15)	$ (7)
OE	15	23	(26)	(25)	(14)	(7)
CEI	20	17	(5)	(6)	-	2
TE	7	6	(3)	(1)	2	4
JCP&L	25	31	(15)	(7)	(6)	(16)
Met-Ed	10	18	(10)	(8)	(4)	(10)
Penelec	19	16	(13)	(9)	(4)	(13)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2010	2009	2008	Other Benefits 2010	2009	2008
Weighted-average discount rate	6.00 %	7.00 %	6.50 %	5.75 %	7.00 %	6.50 %
Expected long-term return on plan assets	8.50 %	9.00 %	9.00 %	8.50 %	9.00 %	9.00 %
Rate of compensation increase	5.20 %	5.20 %	5.20 %			

Accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by accounting guidance are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 assets include registered investment companies, common stocks, publicly traded real estate investment trusts and certain shorter duration, more liquid fixed income securities. Registered investment companies and common stocks are stated at fair value as quoted on a recognized securities exchange and are valued at the last reported sales price on the last business day of the plan year. Market values for real estate investment trusts and certain fixed income securities are based on daily quotes available on public exchanges as with other publicly traded equity and fixed income securities.

Level 2 – Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 investments include common collective trusts, certain real estate investment trusts, and fixed income assets. Common collective trusts are not available in an exchange and active market; however, the fair value is determined based on the underlying investments as traded in an exchange and active market.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value in addition to the use of independent appraisers' estimates of fair value on a periodic basis typically determined quarterly but no less than annually. Assets in this category include private equity, limited partnership, certain real estate trusts and fixed income securities. The fixed income securities' market values are based in part on quantitative models and on observing market value ascertained through timely trades for securities that are similar to the ones being valued.

As of December 31, 2010 and 2009, the pension investments measured at fair value were as follows:

	December 31, 2010				Asset
	Level 1	Level 2	Level 3	Total	Allocation
	(In millions)				
Cash and short-term securities	$ -	$ 72	$ -	$ 72	1 %
Equity investments					
Domestic	342	189	-	531	12 %
International	118	615	-	733	16 %
Fixed income					
Government bonds	-	722	-	722	16 %
Corporate bonds	-	1,414	-	1,414	31 %
Distressed debt	-	97	-	97	2 %
Mortgaged-backed securities (non-government)	-	52	-	52	1 %
Alternatives					
Hedge funds	-	497	-	497	11 %
Private equity funds	-	-	119	119	4 %
Real estate funds	2	-	282	284	6 %
	$ 462	$ 3,658	$ 401	$ 4,521	100 %

	December 31, 2009				Asset
	Level 1	Level 2	Level 3	Total	Allocation
		(In millions)			
Cash and short-term securities	$ -	$ 337	$ -	$ 337	7 %
Equity investments					
Domestic	447	790	-	1,237	28 %
International	131	204	-	335	8 %
Mutual funds	159	-	-	159	4 %
Fixed income					
Government bonds	-	254	-	254	6 %
Corporate bonds	-	1,580	-	1,580	35 %
Distressed debt	-	92	-	92	2 %
Mortgaged-backed securities (non-government)	-	2	-	2	1 %
Alternatives					
Private equity funds	-	-	137	137	3 %
Real estate funds	1	4	241	246	6 %
	$ 738	$ 3,263	$ 378	$ 4,379	100 %

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2010 and 2009:

	Private Equity Funds	Real Estate Funds
Balance as of January 1, 2009	$ 74	$ 342
Actual return on plan assets:		
Unrealized gains (losses)	6	(104)
Realized gains (losses)	1	(1)
Purchases, sales and settlements	12	4
Transfers in (out)	44	-
Balance as of December 31, 2009	137	241
Actual return on plan assets:		
Unrealized gains	1	45
Realized gains (losses)	11	(3)
Purchases, sales and settlements	(28)	(1)
Transfers in (out)	(2)	-
Balance at December 31, 2010	$ 119	$ 282

As of December 31, 2010 and 2009, the other postretirement benefit investments measured at fair value were as follows:

	December 31, 2010				Asset
	Level 1	Level 2	Level 3	Total	Allocation
	(In millions)				
Cash and short-term securities	$ -	$ 16	$ -	$ 16	2 %
Equity investment					
Domestic	178	6	-	184	36 %
International	20	19	-	39	9 %
Mutual funds	7	2	-	9	2 %
Fixed income					
U.S. treasuries	-	27	-	27	5 %
Government bonds	-	143	-	143	28 %
Corporate bonds	-	55	-	55	10 %
Distressed debt	-	3	-	3	1 %
Mortgage-backed securities (non-government)	-	4	-	4	1 %
Alternatives					
Hedge funds	-	15	-	15	3 %
Private equity funds	-	-	3	3	1 %
Real estate funds	-	-	9	9	2 %
	$ 205	$ 290	$ 12	$ 507	100 %

	December 31, 2009				Asset
	Level 1	Level 2	Level 3	Total	Allocation
	(In millions)				
Cash and short-term securities	$ -	$ 19	$ -	$ 19	4 %
Equity investment					
Domestic	180	23	-	203	43 %
International	15	6	-	21	4 %
Mutual funds	10	2	-	12	3 %
Fixed income					
U.S. treasuries	-	20	-	20	4 %
Government bonds	-	123	-	123	26 %
Corporate bonds	-	56	-	56	12 %
Distressed debt	-	3	-	3	1 %
Mortgage-backed securities (non-government)	-	3	-	3	1 %
Alternatives					
Private equity funds	-	-	4	4	1 %
Real estate funds	-	-	7	7	1 %
	$ 205	$ 255	$ 11	$ 471	100 %

The following table provides a reconciliation of changes in the fair value of postretirement benefit investments classified as Level 3 in the fair value hierarchy during 2010 and 2009:

	Private Equity Funds	Real Estate Funds
	(in millions)	
Balance as of January 1, 2009	$ 2	$ 10
Actual return on plan assets:		
Unrealized gains (losses)	-	(3)
Realized gains (losses)	-	-
Purchases, sales and settlements	1	-
Transfers in (out)	1	-
Balance as of December 31, 2009	4	7
Actual return on plan assets:		
Unrealized gains	-	-
Realized gains (losses)	-	2
Purchases, sales and settlements	(1)	-
Transfers in (out)	-	-
Balance at December 31, 2010	$ 3	$ 9

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy generally employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

FirstEnergy's target asset allocations for its pension and OPEB portfolio for 2010 and 2009 are shown in the following table:

	Target Asset Allocations	
	2010	2009
Equities	21 %	58 %
Fixed income	50	30
Absolute return strategies	21	-
Real estate	6	8
Private equity	2	4
Total	100 %	100 %

Assumed Health Care Cost Trend Rates As of December 31	2010	2009
Health care cost trend rate assumed (pre/post-Medicare)	8.0-9.0%	8.5 -10%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5 %	5 %
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2016-2018	2016-2018

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost	$ 2	$ (2)
Effect on accumulated postretirement benefit obligation	$ 22	$ (20)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy and participant contributions:

	Pension Benefits	Other Benefits
	(in millions)	
2011	$ 320	$ 88
2012	332	76
2013	344	61
2014	367	63
2015	381	61
Years 2016-2020	2,068	297

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs – LTIP, EDCP, ESOP and DCPD.

(A) LTIP

FirstEnergy's LTIP includes four stock-based compensation programs – restricted stock, restricted stock units, stock options and performance shares.

Under FirstEnergy's LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2010, 7.2 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2010, 2009 and 2008 were $11 million, $9 million and $43 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded in stockholders' equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the LTIP were as follows:

	2010	2009	2008
Restricted common shares granted	71,752	73,255	82,607
Weighted average market price	$ 38.43	$ 43.68	$ 68.98
Weighted average vesting period (years)	4.74	4.42	5.03
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during 2010 was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2010	648,293	$ 50.39
Nonvested as of December 31, 2010	475,914	51.26
Granted in 2010	71,752	38.43
Vested in 2010	292,152	38.75

FirstEnergy grants two types of restricted stock unit awards: discretionary-based and performance-based. With the discretionary-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in each agreement. With the performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy's stock performance.

	2010	2009	2008
Restricted common shares units granted	511,418	533,399	450,683
Weighted average vesting period (years)	3.00	3.00	3.14

Vesting activity for restricted stock units during 2010 was as follows (forfeitures were not material):

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2010	1,489,187	$ 54.81
Nonvested as of December 31, 2010	1,402,108	48.40
Granted in 2010	511,418	37.13
Vested in 2010	579,736	38.83

Compensation expense recognized in 2010, 2009 and 2008 for restricted stock and restricted stock units, net of amounts capitalized, was approximately $22 million, $25 million and $29 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under FirstEnergy stock option programs during 2010 were as follows:

Stock Option Activities	Number of Shares	Weighted Average Grant-Date Fair value
Balance, January 1, 2010	3,074,626	$ 34.69
(3,074,626 options exercisable)		
Options granted	-	-
Options exercised	180,460	26.86
Options forfeited	5,100	21.61
Balance, December 31, 2010	2,889,066	$ 35.18
(2,889,066 options exercisable)		

Options outstanding and range of exercise price as of December 31, 2010 were as follows:

		Options Outstanding and Exercisable		
Range of Exercise Prices		Shares	Weighted Average Exercise Price	Remaining Contractual Life
$	29.50-29.71	894,054	$ 29.66	1.77
$	34.45-39.46	1,995,012	$ 37.66	2.67
Total		2,889,066	$ 35.18	2.39

FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. As a result, all unvested stock options vested in 2008. No compensation expense was recognized for stock options during 2010 and 2009, and compensation expense in 2008 was not material. Cash received from the exercise of stock options in 2010, 2009 and 2008 was $6 million, $7 million and $74 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense (income) recognized for performance shares during 2010, 2009 and 2008, net of amounts capitalized, totaled approximately ($4) million, $3 million and $8 million, respectively. During 2010, no cash was paid to settle performance shares due to certain criteria not being met for the previous three-year vesting period. Cash used to settle performance shares in 2009 and 2008 was $15 million and $14 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP.

In 2008 and 2009, shares of FirstEnergy common stock were purchased on the market and contributed to participants' accounts. Total ESOP-related compensation expenses in 2010, 2009 and 2008, net of amounts capitalized and dividends on common stock, were $30 million, $36 million and $40 million, respectively.

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. Through December 31, 2010, covered employees received an additional 20% premium in the form of stock units based on the amount allocated to the FirstEnergy stock account. During 2010, the EDCP was amended to cease the 20% stock premium with respect to annual and long-term incentive awards earned during any calendar years that commence on or after January 1, 2011. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Compensation expense (income) recognized on EDCP stock units, net of amounts capitalized, in 2010, 2009 and 2008 was ($3) million, ($0.2) million and ($13) million, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. Funds deferred into the stock account through December 31, 2010, receive a 20% match to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. During 2010, the DCPD was amended to cease the 20% match feature with respect to director's fees earned for service performed during any calendar years that commence on or after January 1, 2011. DCPD expenses recognized in 2010, 2009 and 2008 was $4 million, $3 million and $3 million, respectively. The net liability recognized for DCPD of approximately $5 million as of December 31, 2010, 2009 and 2008 is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

Of the 1.7 million stock units authorized under the EDCP and DCPD, 1,239,415 stock units were available for future awards as of December 31, 2010.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption "short-term borrowings." The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as of December 31, 2010 and 2009:

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy (Consolidated)	$ 13,928	$ 14,845	$ 13,853	$ 14,602
FES	4,279	4,403	4,324	4,406
OE	1,159	1,321	1,169	1,299
CEI	1,853	2,035	1,873	2,032
TE	600	653	600	638
JCP&L	1,810	1,962	1,840	1,950
Met-Ed	742	821	842	909
Penelec	1,120	1,189	1,144	1,177

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy, FES and the Utilities.

(B) INVESTMENTS

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

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

Available-For-Sale Securities

FES and the Utilities hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are considered as available-for-sale at fair market value. FES and the Utilities have no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts as of December 31, 2010 and 2009:

	December 31, 2010[1]				December 31, 2009[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
Debt securities				(In millions)				
FirstEnergy	$ 1,699	$ 31	$ -	$ 1,730	$ 1,727	$ 22	$ -	$ 1,749
FES	980	13	-	993	1,043	3	-	1,046
OE	123	1	-	124	55	-	-	55
TE	42	-	-	42	72	-	-	72
JCP&L	281	9	-	290	271	9	-	280
Met-Ed	127	4	-	131	120	5	-	125
Penelec	145	4	-	149	166	5	-	171
Equity securities								
FirstEnergy	$ 268	$ 69	$ -	$ 337	$ 252	$ 43	$ -	$ 295
JCP&L	80	17	-	97	74	11	-	85
Met-Ed	125	35	-	160	117	23	-	140
Penelec	63	16	-	79	61	9	-	70

(1) Excludes cash balances: FirstEnergy - $193 million; FES - $153 million; OE - $3 million; TE - $34 million; JCP&L - $3 million; Met-Ed - $(3) million and Penelec - $4 million.
(2) Excludes cash balances: FirstEnergy - $137 million; FES - $43 million; OE - $66 million; TE - $2 million; JCP&L - $3 million and Penelec - $23 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2010, 2009 and 2008 were as follows:

December 31, 2010	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 3,172	$ 126	$ 107	$ 79
FES	1,927	92	75	47
OE	83	2	-	3
TE	126	3	1	2
JCP&L	411	10	10	14
Met-Ed	460	13	14	7
Penelec	165	6	7	6

December 31, 2009	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 2,229	$ 226	$ 155	$ 60
FES	1,379	199	117	27
OE	132	11	4	4
TE	169	7	1	2
JCP&L	397	6	12	14
Met-Ed	68	2	13	7
Penelec	84	1	8	6

December 31, 2008	Sales Proceeds	Realized Gains	Realized Losses	Interest and Dividend Income
		(In millions)		
FirstEnergy	$ 1,657	$ 115	$ 237	$ 76
FES	951	99	184	37
OE	121	11	9	5
TE	38	1	-	3
JCP&L	248	1	17	14
Met-Ed	181	2	17	9
Penelec	118	1	10	8

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

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

During 2010, 2009 and 2008, FirstEnergy recognized $55 million, $176 million and $63 million of net realized gains resulting from the sale of securities held in nuclear decommissioning trusts.

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains and losses, and approximate fair values of investments in held-to-maturity securities as of December 31, 2010 and 2009:

	December 31, 2010				December 31, 2009			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
Debt Securities				(In millions)				
FirstEnergy	$ 476	$ 91	$ -	$ 567	$ 544	$ 72	$ -	$ 616
OE	190	51	-	241	217	29	-	246
CEI	340	41	-	381	389	43	-	432

Investments in emission allowances, employee benefits and cost and equity method investments totaling $259 million as of December 31, 2010, and $264 million as of December 31, 2009, are not required to be disclosed and are excluded from the amounts reported above.

Notes Receivable

The table below provides the approximate fair value and related carrying amounts of notes receivable as of December 31, 2010 and 2009. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2013 to 2021.

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Notes Receivable		(In millions)		
FirstEnergy	$ 7	$ 8	$ 36	$ 35
FES	-	-	2	1
TE	104	118	124	141

(C) RECURRING FAIR VALUE MEASUREMENTS

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. A fair value hierarchy has been established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FirstEnergy's Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.

Level 2 – Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FirstEnergy's Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category may include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the long term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. FirstEnergy's Level 3 instruments consist exclusively of NUG contracts.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The determination of the fair value measures takes into consideration various factors. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

The following tables set forth financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of December 31, 2010 and 2009. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair valuation of assets and liabilities and their placement within the fair value hierarchy levels. Transfers between levels are recognized at the end of the reporting period. During 2010, there were no significant transfers between Level 1, Level 2 and Level 3.

FirstEnergy Corp.

The following tables provide the fair value measurement amounts for assets and liabilities recorded on FirstEnergy's Consolidated Balance Sheets at fair value at December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 597	$ -	$ 597
Derivative assets - commodity contracts	-	250	-	250
Derivative assets - NUG contracts[1]	-	-	122	122
Equity securities[2]	338	-	-	338
Foreign government debt securities	-	149	-	149
U.S. government debt securities	-	595	-	595
U.S. state debt securities	-	379	-	379
Other[4]	-	219	-	219
Total assets	$ 338	$ 2,189	$ 122	$ 2,649
Liabilities				
Derivative liabilities – commodity contracts	$ -	$ (348)	$ -	$ (348)
Derivative liabilities – NUG contracts[1]	-	-	(466)	(466)
Total liabilities	$ -	$ (348)	$ (466)	$ (814)
Net assets (liabilities)[3]	$ 338	$ 1,841	$ (344)	$ 1,835

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 484	$ -	$ 484
Derivative assets - commodity contracts	-	34	-	34
Derivative assets - NUG contracts[1]	-	-	200	200
Equity securities[2]	295	-	-	295
Foreign government debt securities	-	279	-	279
U.S. government debt securities	-	558	-	558
U.S. state debt securities	-	478	-	478
Other[4]	-	75	-	75
Total assets	$ 295	$ 1,908	$ 200	$ 2,403
Liabilities				
Derivative liabilities – commodity contracts	$ (11)	$ (224)	$ -	$ (235)
Derivative liabilities – NUG contracts[1]	-	-	(643)	(643)
Total liabilities	$ (11)	$ (224)	$ (643)	$ (878)
Net assets (liabilities)[3]	$ 284	$ 1,684	$ (443)	$ 1,525

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.
(3) Excludes $(7) million and $21 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.
(4) Primarily consists of cash and cash equivalents.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by the Utilities and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2010 Balance	$ 200	$ (643)	$ (443)
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(71)	(110)	(181)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	(7)	287	280
Transfers in (out) of Level 3	-	-	-
December 31, 2010 Balance	$ 122	$ (466)	$ (344)
January 1, 2009 Balance	$ 434	$ (765)	$ (331)
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(234)	(236)	(470)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	-	358	358
Transfers in (out) of Level 3	-	-	-
December 31, 2009 Balance	$ 200	$ (643)	$ (443)

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

FirstEnergy Solutions Corp.

The following tables provide the fair value measurement amounts for assets and liabilities recorded on FES' Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 528	$ -	$ 528
Derivative assets - commodity contracts	-	241	-	241
Foreign government debt securities	-	147	-	147
U.S. government debt securities	-	308	-	308
U.S. state debt securities	-	6	-	6
Other[2]	-	148	-	148
Total assets	$ -	$ 1,378	$ -	$ 1,378
Liabilities				
Derivative liabilities – commodity contracts	$ -	$ (348)	$ -	$ (348)
Total liabilities	$ -	$ (348)	$ -	$ (348)
Net assets (liabilities)[1]	$ -	$ 1,030	$ -	$ 1,030

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 443	$ -	$ 443
Derivative assets - commodity contracts	-	15	-	15
Foreign government debt securities	-	279	-	279
U.S. government debt securities	-	306		306
U.S. state debt securities	-	15	-	15
Other[2]	-	29	-	29
Total assets	$ -	$ 1,087	$ -	$ 1,087
Liabilities				
Derivative liabilities – commodity contracts	$ (11)	$ (224)	$ -	$ (235)
Total liabilities	$ (11)	$ (224)	$ -	$ (235)
Net assets (liabilities)[1]	$ (11)	$ 863	$ -	$ 852

(1) Excludes $7 million and $15 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

Ohio Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on OE's Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
U.S. government debt securities	$ -	$ 124	$ -	$ 124
Other	-	2	-	2
Total assets[1]	$ -	$ 126	$ -	$ 126

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
U.S. government debt securities	$ -	$ 118	$ -	$ 118
Other	-	2	-	2
Total assets[1]	$ -	$ 120	$ -	$ 120

(1) Excludes $1 million as of December 31, 2010 and 2009 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Toledo Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on TE's Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
Assets		(In millions)		
Corporate debt securities	$ -	$ 7	$ -	$ 7
U.S. government debt securities	-	33	-	33
U.S. state debt securities	-	1	-	1
Other[(2)]	-	35	-	35
Total assets[(1)]	$ -	$ 76	$ -	$ 76

December 31, 2009	Level 1	Level 2	Level 3	Total
Assets		(In millions)		
Corporate debt securities	$ -	$ -	$ -	$ -
U.S. government debt securities	-	72	-	72
Other	-	-	-	-
Total assets[(1)]	$ -	$ 72	$ -	$ 72

(1) Excludes $2 million as of December 31, 2009 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

(2) Primarily consists of cash and cash equivalents.

Jersey Central Power & Light Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on JCP&L's Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
Assets		(In millions)		
Corporate debt securities	$ -	$ 23	$ -	$ 23
Derivative assets - commodity contracts	-	2	-	2
Derivative assets - NUG contracts[(1)]	-	-	6	6
Equity securities[(2)]	96	-	-	96
U.S. government debt securities	-	33	-	33
U.S. state debt securities	-	236	-	236
Other	-	4	-	4
Total assets	$ 96	$ 298	$ 6	$ 400
Liabilities				
Derivative liabilities – NUG contracts[(1)]	$ -	$ -	$ (233)	$ (233)
Total liabilities	$ -	$ -	$ (233)	$ (233)
Net assets (liabilities)[(3)]	$ 96	$ 298	$ (227)	$ 167

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 15	$ -	$ 15
Derivative assets - commodity contracts	-	5	-	5
Derivative assets - NUG contracts[1]	-	-	8	8
Equity securities[2]	87	-	-	87
U.S. government debt securities	-	23	-	23
U.S. state debt securities	-	230	-	230
Other	-	12	-	12
Total assets	$ 87	$ 285	$ 8	$ 380
Liabilities				
Derivative liabilities – NUG contracts[1]	$ -	$ -	$ (399)	$ (399)
Total liabilities	$ -	$ -	$ (399)	$ (399)
Net assets (liabilities)[3]	$ 87	$ 285	$ (391)	$ (19)

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.
(3) Excludes $(3) million as of December 31, 2010 of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by JCP&L and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2010 Balance	$ 8	$ (399)	$ (391)
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(1)	36	35
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	(1)	130	129
Transfers in (out) of Level 3	-	-	-
December 31, 2010 Balance	$ 6	$ (233)	$ (227)
January 1, 2009 Balance	$ 14	$ (531)	$ (517)
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(6)	(36)	(42)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	-	168	168
Transfers in (out) of Level 3	-	-	-
December 31, 2009 Balance	$ 8	$ (399)	$ (391)

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

Metropolitan Edison Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on Met-Ed's Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 32	$ -	$ 32
Derivative assets - commodity contracts	-	5	-	5
Derivative assets - NUG contracts(1)	-	-	112	112
Equity securities(2)	160	-	-	160
Foreign government debt securities	-	1	-	1
U.S. government debt securities	-	88	-	88
U.S. state debt securities	-	2	-	2
Other	-	14	-	14
Total assets	$ 160	$ 142	$ 112	$ 414
Liabilities				
Derivative liabilities – NUG contracts(1)	$ -	$ -	$ (116)	$ (116)
Total liabilities	$ -	$ -	$ (116)	$ (116)
Net assets (liabilities)(3)	$ 160	$ 142	$ (4)	$ 298

December 31, 2009	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 20	$ -	$ 20
Derivative assets - commodity contracts	-	9	-	9
Derivative assets - NUG contracts(1)	-	-	176	176
Equity securities(2)	133	-	-	133
U.S. government debt securities	-	30	-	30
U.S. state debt securities	-	82	-	82
Other	-	2	-	2
Total assets	$ 133	$ 143	$ 176	$ 452
Liabilities				
Derivative liabilities – NUG contracts(1)	$ -	$ -	$ (143)	$ (143)
Total liabilities	$ -	$ -	$ (143)	$ (143)
Net assets (liabilities)(3)	$ 133	$ 143	$ 33	$ 309

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.
(3) Excludes $(9) million and $1 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts held by Met-Ed and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2010 Balance	$ 176	$ (143)	$ 33
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(59)	(38)	(97)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	(5)	65	60
Transfers in (out) of Level 3	-	-	-
December 31, 2010 Balance	$ 112	$ (116)	$ (4)
January 1, 2009 Balance	$ 300	$ (150)	$ 150
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(124)	(81)	(205)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	-	88	88
Transfers in (out) of Level 3	-	-	-
December 31, 2009 Balance	$ 176	$ (143)	$ 33

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

Pennsylvania Electric Company

The following tables provide the fair value measurement amounts for assets and liabilities recorded on Penelec's Consolidated Balance Sheets at fair value as of December 31, 2010 and 2009:

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In millions)		
Assets				
Corporate debt securities	$ -	$ 8	$ -	$ 8
Derivative assets - commodity contracts	-	2	-	2
Derivative assets - NUG contracts[1]	-	-	4	4
Equity securities[2]	81	-	-	81
U.S. government debt securities	-	9	-	9
U.S. state debt securities	-	133	-	133
Other	-	5	-	5
Total assets	$ 81	$ 157	$ 4	$ 242
Liabilities				
Derivative liabilities – NUG contracts[1]	$ -	$ -	$ (117)	$ (117)
Total liabilities	$ -	$ -	$ (117)	$ (117)
Net assets (liabilities)[3]	$ 81	$ 157	$ (113)	$ 125

December 31, 2009	Level 1	Level 2	Level 3	Total
Assets		*(In millions)*		
Corporate debt securities	$ -	$ 6	$ -	$ 6
Derivative assets - commodity contracts	-	5	-	5
Derivative assets - NUG contracts[1]	-	-	16	16
Equity securities[2]	74	-	-	74
U.S. government debt securities	-	9	-	9
U.S. state debt securities	-	151	-	151
Other	-	20	-	20
Total assets	$ 74	$ 191	$ 16	$ 281
Liabilities				
Derivative liabilities – NUG contracts[1]	$ -	$ -	$ (101)	$ (101)
Total liabilities	$ -	$ -	$ (101)	$ (101)
Net assets (liabilities)[3]	$ 74	$ 191	$ (85)	$ 180

(1) NUG contracts are subject to regulatory accounting and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Index or Russell 3000 Index.
(3) Excludes $(3) million and $3 million as of December 31, 2010 and 2009, respectively, of receivables, payables and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG and commodity contracts held by Penelec and classified as Level 3 in the fair value hierarchy for the years ending December 31, 2010 and 2009:

	Derivative Asset NUG Contracts[1]	Derivative Liability NUG Contracts[1]	Net NUG Contracts[1]
		(In millions)	
January 1, 2010 Balance	$ 16	$ (101)	$ (85)
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(11)	(108)	(119)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	(1)	92	91
Transfers in (out) of Level 3	-	-	-
December 31, 2010 Balance	$ 4	$ (117)	$ (113)
January 1, 2009 Balance	$ 120	$ (84)	$ 36
Realized gain (loss)	-	-	-
Unrealized gain (loss)	(104)	(119)	(223)
Purchases	-	-	-
Issuances	-	-	-
Sales	-	-	-
Settlements	-	102	102
Transfers in (out) of Level 3	-	-	-
December 31, 2009 Balance	$ 16	$ (101)	$ (85)

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

6. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas and energy transmission. To manage the volatility relating to these exposures, FirstEnergy uses a variety of derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used for risk management purposes. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practices.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for at cost under the accrual method of accounting. The changes in the fair value of derivative instruments that do not meet the normal purchases and normal sales criteria are included in purchased power, other expense, unrealized gain (loss) on derivative hedges in other comprehensive income (loss), or as part of the value of the hedged item. Based on derivative contracts held as of December 31, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $16 million ($10 million net of tax) during the next twelve months. A hypothetical 10% increase in the interest rates associated with variable-rate debt would decrease annual net income by approximately $1 million.

Cash Flow Hedges

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of December 31, 2010, no forward starting swap agreements were outstanding.

Total unamortized losses included in AOCL associated with prior interest rate cash flow hedges totaled $92 million ($60 million net of tax) as of December 31, 2010. Based on current estimates, approximately $11 million will be amortized to interest expense during the next twelve months. The table below provides the activity of AOCL related to interest rate cash flow hedges for the years ended December 31, 2010 and 2009.

	Years Ended December 31,	
	2010	2009
	(In millions)	
Effective Portion		
Loss Recognized in AOCL	$ -	$ (18)
Reclassification from AOCL into Interest Expense	(11)	(40)

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivatives were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of December 31, 2010, no fixed-for-floating interest rate swap agreements were outstanding.

Total unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $124 million ($80 million net of tax) as of December 31, 2010. Based on current estimates, approximately $22 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled $12 million during 2010.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

The following tables summarize the fair value of commodity derivatives on FirstEnergy's Consolidated Balance Sheets:

Cash Flow Hedges

Derivative Assets	**Fair Value**		**Derivative Liabilities**	**Fair Value**	
	December 31, 2010	**December 31, 2009**		**December 31, 2010**	**December 31, 2009**
	(In millions)			*(In millions)*	
Electricity Forwards			Electricity Forwards		
Current Assets	$ 55	$ 3	Current Liabilities	$ 58	$ 7
Noncurrent Assets	49	11	Noncurrent Liabilities	43	12
Natural Gas Futures			Natural Gas Futures		
Current Assets	-	-	Current Liabilities	-	9
Noncurrent Assets	-	-	Noncurrent Liabilities	-	-
Other			Other		
Current Assets	-	-	Current Liabilities	-	2
Noncurrent Assets	-	-	Noncurrent Liabilities	-	-
	$ 104	$ 14		$ 101	$ 30

Economic Hedges

Derivative Assets	**Fair Value**		**Derivative Liabilities**	**Fair Value**	
	December 31, 2010	**December 31, 2009**		**December 31, 2010**	**December 31, 2009**
	(In millions)			*(In millions)*	
NUG Contracts			NUG Contracts		
Power Purchase			Power Purchase		
Contract Asset	$ 122	$ 200	Contract Liability	$ 466	$ 643
Other			Other		
Current Assets	96	-	Current Liabilities	208	106
Noncurrent Assets	50	19	Noncurrent Liabilities	38	97
	268	219		712	846
Total Commodity Derivatives	$ 372	$ 233	Total Commodity Derivatives	$ 813	$ 876

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas, primarily used in FirstEnergy's peaking units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs. The following table summarizes the volume of FirstEnergy's outstanding derivative transactions as of December 31, 2010:

	Purchases	**Sales**	**Net**	**Units**
		(In thousands)		
Electricity Forwards	42,227	(45,164)	(2,937)	MWH

The effect of derivative instruments on the Consolidated Statements of Income and Comprehensive Income for the years ended December 31, 2010 and 2009 are summarized in the following tables:

Derivatives in Cash Flow Hedging Relationships	**Electricity Forwards**	**Natural Gas Futures**	**Heating Oil Futures**	**Total**
		(In millions)		
2010				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ -	$ (1)	$ -	$ (1)
Effective Gain (Loss) Reclassified to: [(1)]				
Purchased Power Expense	(12)	-	-	(12)
Fuel Expense	-	(10)	(3)	(13)
2009				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 7	$ (9)	$ 1	$ (1)
Effective Gain (Loss) Reclassified to: [(1)]				
Purchased Power Expense	(6)	-	-	(6)
Fuel Expense	-	(9)	(12)	(21)

(1) The ineffective portion was immaterial.

Derivatives Not in Hedging Relationships	NUG Contracts	Other	Total
		(In millions)	
2010			
Unrealized Gain (Loss) Recognized in:			
Purchased Power Expense	$ -	$ (24)	$ (24)
Regulatory Assets (1)	(181)	-	(181)
	$ (181)	$ (24)	$ (205)
Realized Gain (Loss) Reclassified to:			
Purchased Power Expense	$ -	$ (118)	$ (118)
Regulatory Assets (1)	(279)	9	(270)
	$ (279)	$ (109)	$ (388)
2009			
Unrealized Gain (Loss) Recognized in:			
Purchased Power Expense	$ -	$ (203)	$ (203)
Fuel Expense	-	(1)	(1)
Regulatory Assets (1)	(470)	-	(470)
	$ (470)	$ (204)	$ (674)
Realized Gain (Loss) Reclassified to:			
Purchased Power Expense	$ -	$ 1	$ 1
Fuel Expense	-	(1)	(1)
Regulatory Assets (1)	(358)	10	(348)
	$ (358)	$ 10	$ (348)

(1) The realized gain (loss) is reclassified upon termination of the derivative instrument.

Total unamortized gains included in AOCL associated with commodity derivatives were $8 million ($5 million net of tax) as of December 31, 2010, as compared to unamortized losses of $15 million ($9 million net of tax) as of December 31, 2009. The net of tax change resulted from a net $1 million loss related to current hedging activity offset by $15 million of net hedge losses reclassified to earnings during 2010. Based on current estimates, approximately $3 million (net of tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2010 are expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuates from period to period based on various market factors.

As of December 31, 2010, FES' net liability position under commodity derivative contracts was $107 million. Under these commodity derivative contracts, FES posted collateral of $156 million. Certain commodity derivative contracts include credit risk-related contingent features that would require FES to post additional collateral if the credit rating for its debt were to fall below investment grade. The aggregate fair value of derivative instruments with credit risk-related contingent features that were in a liability position on December 31, 2010 was $102 million, for which $91 million in collateral has been posted. If FES' credit rating were to fall below investment grade, it would be required to post $24 million of additional collateral related to commodity derivatives.

7. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO and FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

In 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases.

During 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Rentals for capital and operating leases for the three years ended December 31, 2010 are summarized as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
2010				*(In millions)*				
Operating leases	$ 228	$ 202	$ 147	$ 4	$ 64	$ 9	$ 7	$ 4
Capital leases								
Interest element	2	1	-	1	-	-	-	-
Other(1)	11	10	-	-	-	-	1	-
Total rentals	$ 241	$ 213	$ 147	$ 5	$ 64	$ 9	$ 8	$ 4
2009								
Operating leases	$ 236	$ 202	$ 146	$ 4	$ 64	$ 9	$ 7	$ 4
Capital leases								
Interest element	1	2	1	1	-	-	-	-
Other(1)	6	10	-	-	-	-	-	-
Total rentals	$ 243	$ 214	$ 147	$ 5	$ 64	$ 9	$ 7	$ 4
2008								
Operating leases	$ 381	$ 173	$ 146	$ 5	$ 65	$ 8	$ 4	$ 4
Capital leases								
Interest element	1	1	-	-	-	-	-	-
Other(1)	6	8	-	1	-	-	-	-
Total rentals	$ 388	$ 182	$ 146	$ 6	$ 65	$ 8	$ 4	$ 4

(1) Includes $6 million in 2010 and 2009, respectively, and $5 million in 2008, at FE and FES for wind purchased power agreements classified as capital leases.

The future minimum capital lease payments as of December 31, 2010 are as follows (OE, TE, JCP&L, Met-Ed and Penelec have no material capital leases):

Capital leases	FE	FES	CEI
		(In millions)	
2011	$ 7	$ 6	$ 1
2012	7	6	1
2013	7	6	1
2014	7	6	1
2015	7	5	1
Years thereafter	14	12	2
Total minimum lease payments	49	41	7
Executory costs	-	-	-
Net minimum lease payments	49	41	7
Interest portion	(10)	(5)	(4)
Present value of net minimum lease payments	39	36	3
Less current portion	5	5	-
Noncurrent portion	$ 34	$ 31	$ 3

The present value of minimum lease payments for FirstEnergy does not include $15 million of capital lease obligations that were prepaid as of December 31, 2010.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 8).

The future minimum consolidated operating lease payments as of December 31, 2010 are as follows:

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 recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The unamortized above-market lease liability for Beaver Valley Unit 2 of $236 million as of December 31, 2010, of which $37 million is classified as current, is being amortized by TE on a straight-line basis through the end of the lease term in 2017. The unamortized above-market lease liability for the Bruce Mansfield Plant of $262 million as of December 31, 2010, of which $46 million is classified as current, is being amortized by FGCO on a straight-line basis through the end of the lease term in 2016.

8. VARIABLE INTEREST ENTITIES

On January 1, 2010, FirstEnergy adopted the amendments to the consolidation topic addressing VIEs. This standard requires that FirstEnergy and its subsidiaries perform a qualitative analysis to determine whether a variable interest gives FirstEnergy or its subsidiaries a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impacts the entity's economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. This standard also requires an ongoing reassessment of the primary beneficiary of a VIE and eliminates the quantitative approach previously required for determining whether an entity is the primary beneficiary. In order to evaluate contracts under the consolidation guidance, FirstEnergy aggregated contracts into categories based on similar risk characteristics and significance. The adoption of this new standard did not result in a change in the consolidation of VIEs by FirstEnergy or its subsidiaries.

FirstEnergy's consolidated financial statements include the accounts of entities in which it has a controlling financial interest. FirstEnergy consolidates certain VIEs in which it has financial control through disproportionate economics in its equity and debt investments in the entities. These VIEs include: FEV's joint venture in the Signal Peak mining and coal transportation operations; the PNBV and Shippingport bond trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; and wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station, of which $310 million was outstanding as of December 31, 2010.

FirstEnergy and its subsidiaries reflect the portion of VIEs not owned by them in the caption noncontrolling interest within the consolidated financial statements. The change in noncontrolling interest on the Consolidated Balance Sheets is the result of net losses of the noncontrolling interests ($24 million) and distributions to owners ($5 million) during the year ended December 31, 2010.

Mining Operations

On July 16, 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 Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made a $125 million equity investment in the joint venture, which acquired 80% of the mining operations (Signal Peak Energy, LLC) and 100% of the transportation operations, with FEV owning a 45% economic interest and an affiliate of WMB Loan Ventures LLC and WMB Loan Ventures II LLC owning a 55% economic interest in the joint venture. Both parties have a 50% voting interest in the joint venture. FEV consolidates the mining and transportation operations of this joint venture in its financial statements. In March 2009, FEV agreed to pay a total of $8.5 million to affiliates of WMB Loan Ventures LLC and WMB Loan Ventures II LLC to purchase an additional 5% economic interest in the Signal Peak mining and coal transportation operations. Voting interests remained unchanged after the sale was completed in July 2009. Effective August 21, 2009, the joint venture acquired the remaining 20% stake in the mining operations by issuing a five-year note for $47.5 million. For both acquisitions, the difference between the consideration paid and the adjustment to the noncontrolling interest resulted in a charge to other paid in capital of approximately $30 million.

Trusts

FirstEnergy's consolidated financial statements include PNBV and Shippingport, VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with sale and leaseback transactions. PNBV and Shippingport financial data are included in the consolidated financial statements of OE and CEI, respectively.

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE's 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. Shippingport was established to purchase all of the lease obligation bonds issued in connection with CEI's and TE's Bruce Mansfield Plant sale and leaseback transaction in 1987. CEI and TE used debt and available funds to purchase the notes issued by Shippingport.

Power Purchase Agreements

FirstEnergy subsidiaries JCPL, Met-Ed and Penelec have 21 long term power purchase agreements totaling 1,339 MW with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities. FirstEnergy evaluated these power purchase agreements to determine if certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Utilities and the contract price for power is correlated with the plant's variable costs of production.

FirstEnergy has determined that for all but two of these NUG entities, neither JCP&L, nor Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations that are not within the scope of consolidation consideration for VIEs. JCP&L may hold variable interests in the remaining two entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. However, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Since JCP&L has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. Purchased power costs related to the two contracts that may contain a variable interest were $243 million and $225 million for the years ended December 31, 2010 and 2009, respectively.

Loss Contingencies

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

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions mentioned above as of December 31, 2010:

	Maximum Exposure	Discounted Lease Payments, net [1]	Net Exposure
		(In millions)	
FES	$ 1,360	$ 1,167	$ 193
OE	666	474	192
CEI[2]	622	72	550
TE[2]	622	346	276

(1) The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.6 billion.

(2) CEI and TE are jointly and severally liable for the maximum loss amounts under certain sale-leaseback agreements.

See Note 7 for a discussion of CEI's and TE's assignment of their leasehold interests in the Bruce Mansfield Plant to FGCO.

9. INCOME TAXES

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2010 are shown below:

PROVISION FOR INCOME TAXES	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2010								
Currently payable-								
Federal	$ (23)	$ (23)	$ 37	$ 58	$ (9)	$ 81	$ 1	$ (81)
State	35	(2)	(2)	1	(1)	36	12	(12)
	12	(25)	35	59	(10)	117	13	(93)
Deferred, net-								
Federal	451	165	45	(15)	27	30	33	117
State	28	15	3	(4)	1	1	(3)	17
	479	180	48	(19)	28	31	30	134
Investment tax credit amortization	(9)	(4)	(1)	(1)	-	-	-	-
Total provision for income taxes	$ 482	$ 151	$ 82	$ 39	$ 18	$ 148	$ 43	- 41
2009								
Currently payable-								
Federal	$ (183)	$ 87	$ 21	$ 40	$ 6	$ 40	$ (34)	$ (21)
State	44	8	4	2	-	26	(4)	4
	(139)	95	25	42	6	66	(38)	(17)
Deferred, net-								
Federal	351	200	40	(52)	-	41	60	60
State	42	24	3	1	2	2	7	4
	393	224	43	(51)	2	43	67	64
Investment tax credit amortization	(9)	(4)	(2)	(1)	-	-	-	(1)
Total provision for income taxes	$ 245	$ 315	$ 66	$ (10)	$ 8	$ 109	$ 29	$ 46
2008								
Currently payable-								
Federal	$ 355	$ 156	$ 79	$ 119	$ 46	$ 101	$ 5	$ (34)
State	56	20	4	6	-	34	6	(3)
	411	176	83	125	46	135	11	(37)
Deferred, net-								
Federal	343	109	22	16	(12)	9	47	84
State	36	12	(2)	(2)	(4)	4	4	12
	379	121	20	14	(16)	13	51	96
Investment tax credit amortization	(13)	(4)	(4)	(2)	-	-	(1)	(1)
Total provision for income taxes	$ 777	$ 293	$ 99	$ 137	$ 30	$ 148	$ 61	$ 58

As a result of the Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act signed into law on March 23, 2010 and March 30, 2010, respectively, beginning in 2013 the tax deduction available to FirstEnergy will be reduced to the extent that drug costs are reimbursed under the Medicare Part D retiree subsidy program. As retiree healthcare liabilities and related tax impacts under prior law were already reflected in FirstEnergy's consolidated financial statements, the change resulted in a charge to FirstEnergy's earnings in 2010 of approximately $13 million and a reduction in accumulated deferred tax assets associated with these subsidies. This change reflects the anticipated increase in income taxes that will occur as a result of the change in tax law.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2010.

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2010								
Book income before provision for income taxes	$ 1,266	$ 420	$ 239	$ 110	$ 51	$ 340	$ 101	$ 101
Federal income tax expense at statutory rate	$ 443	$ 147	$ 84	$ 39	$ 18	$ 119	$ 35	$ 35
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(9)	(4)	(1)	(1)	-	-	-	-
State income taxes, net of federal tax benefit	41	9	1	(2)	-	24	6	3
Manufacturing deduction	-	2	(2)	-	-	-	-	-
Medicare Part D	13	-	-	3	1	3	2	3
Effectively settled tax items	(34)	(2)	(9)	(4)	(3)	-	-	-
Other, net	28	(1)	9	4	2	2	-	-
Total provision for income taxes	$ 482	$ 151	$ 82	$ 39	$ 18	$ 148	$ 43	$ 41
2009								
Book income before provision for income taxes	$ 1,251	$ 892	$ 188	$ (23)	$ 32	$ 279	$ 84	$ 111
Federal income tax expense at statutory rate	$ 438	$ 312	$ 66	$ (8)	$ 11	$ 98	$ 29	$ 39
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(9)	(4)	(2)	(1)	-	-	-	(1)
State income taxes, net of federal tax benefit	56	21	5	2	1	18	2	5
Manufacturing deduction	(13)	(11)	(2)	1	(1)	-	-	-
Effectively settled tax items	(217)	-	-	-	-	-	-	-
Other, net	(10)	(3)	(1)	(4)	(3)	(7)	(2)	3
Total provision for income taxes	$ 245	$ 315	$ 66	$ (10)	$ 8	$ 109	$ 29	$ 46
2008								
Book income before provision for income taxes	$ 2,119	$ 800	$ 310	$ 421	$ 105	$ 335	$ 149	$ 146
Federal income tax expense at statutory rate	$ 742	$ 280	$ 109	$ 147	$ 37	$ 117	$ 52	$ 51
Increases (reductions) in taxes resulting from-								
Amortization of investment tax credits	(13)	(4)	(4)	(2)	-	-	(1)	(1)
State income taxes, net of federal tax benefit	60	21	1	2	(2)	25	7	5
Manufacturing deduction	(29)	(16)	(3)	(8)	(2)	-	-	-
Effectively settled tax items	(14)	-	-	-	-	-	-	-
Other, net	31	12	(4)	(2)	(3)	6	3	3
Total provision for income taxes	$ 777	$ 293	$ 99	$ 137	$ 30	$ 148	$ 61	$ 58

Accumulated deferred income taxes as of December 31, 2010 and 2009 are as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
DECEMBER 31, 2010								
Property basis differences	$ 3,617	$ 645	$ 571	$ 471	$ 196	$ 651	$ 354	$ 439
Regulatory transition charge	235	12	37	89	3	95	(1)	-
Customer receivables for future income taxes	113	-	-	-	-	13	48	52
Deferred customer shopping incentive	-	-	-	-	-	-	-	-
Deferred MISO/PJM transmission costs	85	-	-	-	-	-	62	23
Other regulatory assets - RCP	166	-	82	56	28	-	-	-
Deferred sale and leaseback gain	(469)	(412)	(35)	-	-	(10)	(12)	-
Nonutility generation costs	51	-	-	-	-	-	55	(4)
Unamortized investment tax credits	(44)	(20)	(4)	(4)	(2)	(2)	(5)	(4)
Unrealized losses on derivative hedges	(29)	-	-	-	-	-	-	-
Pension and other postretirement obligations	(686)	(99)	(57)	(31)	(27)	(74)	(13)	(81)
Lease market valuation liability	(197)	(82)	-	-	(81)	-	-	-
Oyster Creek securitization (Note 11(C))	109	-	-	-	-	109	-	-
Nuclear decommissioning activities	47	79	7	(1)	15	(8)	2	(47)
Mark-to-market adjustments	(42)	(42)	-	-	-	-	-	-
Deferred gain for asset sales - affiliated companies	-	-	34	22	7	-	-	-
Allowance for equity funds used used during construction	12	-	12	-	-	-	-	-
Loss carryforwards	(41)	(10)	-	-	-	-	-	(23)
Loss carryforward valuation reserve	21	9	-	-	-	-	-	7
All other	(69)	(22)	49	21	(7)	(58)	(17)	10
Net deferred income tax liability	$ 2,879	$ 58	$ 696	$ 623	$ 132	$ 716	$ 473	$ 372
DECEMBER 31, 2009								
Property basis differences	$ 3,049	$ 619	$ 508	$ 419	$ 177	$ 458	$ 275	$ 350
Regulatory transition charge	334	-	67	95	2	157	13	-
Customer receivables for future income taxes	111	-	-	-	-	13	49	49
Deferred customer shopping incentive	55	-	-	55	-	-	-	-
Deferred MISO/PJM transmission costs	89	-	-	-	-	-	90	(1)
Other regulatory assets - RCP	162	-	80	54	28			-
Deferred sale and leaseback gain	(486)	(426)	(40)	-	-	(9)	(11)	-
Nonutility generation costs	9	-	-	-	-	-	48	(39)
Unamortized investment tax credits	(48)	(22)	(4)	(4)	(2)	(2)	(5)	(4)
Unrealized losses on derivative hedges	(44)	(8)	-	-	-	(1)	(1)	-
Pension and other postretirement obligations	(611)	(75)	(57)	(18)	(34)	(72)	(20)	(83)
Lease market valuation liability	(232)	(101)	-	-	(111)	-	-	-
Oyster Creek securitization (Note 11(C))	132	-	-	-	-	132	-	-
Nuclear decommissioning activities	(34)	23	5	-	12	(19)	(1)	(52)
Mark-to-market adjustments	(76)	(76)	-	-	-	-	-	-
Deferred gain for asset sales - affiliated companies	-	-	37	25	8	-	-	-
Allowance for equity funds used used during construction	15	-	15	-	-	-	-	-
Loss carryforwards	(33)	(8)	-	-	-	-	-	(13)
Loss carryforward valuation reserve	21	7	-	-	-	-	-	5
All other	55	(20)	49	19	1	31	16	30
Net deferred income tax liability (asset)	$ 2,468	$ (87)	$ 660	$ 645	$ 81	$ 688	$ 453	$ 242

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. After reaching settlements at appeals in 2010 related primarily to the capitalization of certain costs for the tax years 2004-2008 and an unrelated federal tax matter related to prior year gains and losses recognized from the disposition of assets, as well as receiving final approval from the Joint Committee on Taxation for several items that were under appeals for tax years 2001-2003, FirstEnergy recognized approximately $78 million of net tax benefits in 2010, including $21 million that favorably affected FirstEnergy's effective tax rate. The remaining portion of the tax benefit increased FirstEnergy's accumulated deferred income taxes.

Upon reaching a settlement on several items under appeal for the tax years 2001-2003, as well as other items that effectively settled in 2009, FirstEnergy recognized approximately $100 million of net tax benefits, including $161 million that favorably affected FirstEnergy's effective tax rate. The offsetting $61 million primarily related to tax items where the uncertainty was removed and the tax refund will be received when the tax years are closed.

Upon completion of the federal tax examinations for tax years 2004-2006, as well as other tax settlements reached in 2008, FirstEnergy recognized approximately $42 million of net tax benefits, including $7 million that favorably affected FirstEnergy's effective tax rate. The remaining balance of the tax benefits recognized in 2008 adjusted goodwill as a purchase price adjustment ($20 million) and accumulated deferred income taxes for temporary tax items ($15 million).

As of December 31, 2010, it is reasonably possible that approximately $42 million of the unrecognized benefits may be resolved within the next twelve months, of which up to approximately $2 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs and various state tax items.

In 2009, FirstEnergy, on behalf of the Utilities, filed a change in accounting method related to the costs to repair and maintain electric utility network (transmission and distribution) assets. In 2010, approximately $325 million of costs were included as a repair deduction on FirstEnergy's 2009 consolidated tax return, which reduced taxable income and increased the amount of tax refunds that were applied to FirstEnergy's 2010 estimated federal tax payments. Due to the flow through of the Pennsylvania state income tax benefit for this change in accounting, FirstEnergy's effective tax rate was reduced by $6 million in 2010. In connection with completing FirstEnergy's 2009 consolidated tax return, FES recognized an $8 million adjustment that increased its income tax expense in 2010. The effects of these adjustments were not material to 2009 or 2010.

In 2008, FirstEnergy, on behalf of FGCO and NGC, filed a change in accounting method related to the costs to repair and maintain electric generation stations. During the second quarter of 2009, the IRS approved the change in accounting method and $281 million of costs were included as a repair deduction on FirstEnergy's 2008 consolidated tax return. Since the IRS did not complete its review over this change in accounting method by the extended filing date of FirstEnergy's federal tax return, FirstEnergy increased the amount of unrecognized tax benefits by $34 million in the third quarter of 2009, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item. There was no impact on FirstEnergy's effective tax rate for 2009.

The changes in unrecognized tax benefits for the three years ended December 31, 2010 are as follows:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance, January 1, 2010	$ 191	$ 41	$ 77	$ 29	$ 6	$ 14	$ 13	$ 11
Increase for tax positions related to the current year	10	6	2	(1)	-	-	2	1
Increase for tax positions related to prior years	2	-	-	-	-	-	-	-
Decrease for tax positions related to prior years	(81)	(4)	(19)	(15)	(6)	(21)	(2)	(5)
Decrease for settlement	(77)	(2)	(58)	(14)	-	7	(11)	(6)
Balance, December 31, 2010	$ 45	$ 41	$ 2	$ (1)	$ -	$ -	$ 2	$ 1
Balance, January 1, 2009	$ 219	$ 5	$ (30)	$ (26)	$ (4)	$ 42	$ 28	$ 24
Increase for tax positions related to the current year	41	34	4	3	-	-	-	-
Increase for tax positions related to prior years	46	2	103	52	10	-	-	-
Decrease for tax positions related to prior years	(100)	-	-	-	-	(28)	(15)	(13)
Decrease for settlement	(15)	-	-	-	-	-	-	-
Balance, December 31, 2009	$ 191	$ 41	$ 77	$ 29	$ 6	$ 14	$ 13	$ 11
Balance, January 1, 2008	$ 272	$ 14	$ (12)	$ (17)	$ (1)	$ 38	$ 24	$ 16
Increase for tax positions related to the current year	14	-	1	-	-	-	-	-
Increase for tax positions related to prior years	-	1	1	-	-	6	5	9
Decrease for tax positions related to prior years	(56)	(10)	(14)	(8)	(3)	(2)	(1)	(1)
Decrease for settlement	(11)	-	(6)	(1)	-	-	-	-
Balance, December 31, 2008	$ 219	$ 5	$ (30)	$ (26)	$ (4)	$ 42	$ 28	$ 24

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. The reversal of accrued interest associated with the recognized tax benefits noted above favorably affected FirstEnergy's effective tax rate by $12 million in 2010. The reversal of accrued interest associated with the $161 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2009 by $56 million and an interest receivable of $11 million was removed from the accrued interest for uncertain tax positions. The reversal of accrued interest associated with the $56 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2008 by $12 million and an interest receivable of $4 million was removed from the accrued interest for uncertain tax positions. During the years ended December 31, 2010, 2009 and 2008, FirstEnergy recognized net interest expense (income) of approximately $(10) million, $(49) million and $2 million, respectively. The net amount of interest accrued as of December 31, 2010 and 2009 was $3 million and $21 million, respectively.

The following table summarizes the net interest expense (income) recognized by FES and the Utilities for the three years ended December 31, 2010 and the cumulative net interest payable (receivable) as of December 31, 2010 and 2009:

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2010	2009	2008	2010	2009
		(In millions)		(In millions)	
FES	$ 1	$ (1)	$ -	$ 2	$ 2
OE	(3)	4	(4)	1	9
CEI	(2)	3	(2)	-	3
TE	(1)	-	-	-	1
JCP&L	(2)	(4)	1	-	1
Met-Ed	-	(2)	1	-	1
Penelec	-	(1)	2	-	1

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2008-2010) and state tax authorities. Tax returns for all state jurisdictions are open from 2006-2009. The IRS began auditing the year 2008 in February 2008 and the audit was completed in July 2010 with one item under appeal. The 2009 tax year audit began in February 2009 and the 2010 tax year audit began in February 2010. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition or results of operations.

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $1.6 billion, of which $724 million is expected to be utilized. The associated deferred tax assets are $20 million. These losses expire as follows:

Expiration Period	FE	FES	Penelec
		(In millions)	
2011-2015	$ 532	$ 321	$ -
2016-2020	112	15	14
2021-2025	480	4	186
2026-2030	524	230	150
	$ 1,648	$ 570	$ 350

General Taxes

Details of general taxes for the three years ended December 31, 2010 are shown below:

	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
2010								
Kilowatt-hour excise	$ 245	$ 5	$ 92	$ 68	$ 27	$ 51	$ -	$ -
State gross receipts	185	17	15	-	-	-	85	68
Real and personal property	243	53	67	70	23	5	-	(1)
Social security and unemployment	86	14	8	5	2	9	4	5
Other	17	5	1	-	-	-	(1)	1
Total general taxes	$ 776	$ 94	$ 183	$ 143	$ 52	$ 65	$ 88	$ 73
2009								
Kilowatt-hour excise(1)	$ 224	$ 1	$ 84	$ 66	$ 24	$ 49	$ -	$ -
State gross receipts	171	14	15	-	-	-	78	63
Real and personal property	253	53	64	74	21	5	2	2
Social security and unemployment	90	14	8	5	3	9	5	6
Other	15	5	-	-	-	-	3	3
Total general taxes	$ 753	$ 87	$ 171	$ 145	$ 48	$ 63	$ 88	$ 74
2008								
Kilowatt-hour excise	$ 249	$ 1	$ 97	$ 70	$ 30	$ 51	$ -	$ -
State gross receipts	183	16	17	-	-	-	79	70
Real and personal property	240	53	61	67	19	5	3	2
Social security and unemployment	95	14	9	6	3	10	5	6
Other	11	4	2	-	-	1	(1)	2
Total general taxes	$ 778	$ 88	$ 186	$ 143	$ 52	$ 67	$ 86	$ 80

(1) Kilowatt-hour excise tax for OE and TE includes a $7.1 million and $3.5 million adjustment, respectively, recognized in 2009 related to prior periods.

10. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

Federally-enforceable 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 these reliability standards 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 implemented and enforced by the Reliability*First* Corporation.

FirstEnergy believes that it generally 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, 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.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations resulting in customers losing power for up to eleven hours. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. NERC has submitted first and second Requests for Information regarding this and another related matter. JCP&L is complying with these requests. JCP&L is not able to predict what actions, if any, that the NERC may take with respect to this matter.

On August 23, 2010, FirstEnergy self-reported to Reliability*First* a vegetation encroachment event on a Met-Ed 230 kV line. This event did not result in a fault, outage, operation of protective equipment, or any other meaningful electric effect on any FirstEnergy transmission facilities or systems. On August 25, 2010, Reliability*First* issued a Notice of Enforcement to investigate the incident. FirstEnergy submitted a data response to Reliability*First* on September 27, 2010. At this time, FirstEnergy is unable to predict the outcome of this investigation.

(B) OHIO

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.

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.

(C) PENNSYLVANIA

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.

(D) NEW JERSEY

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.

(E) 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.

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.

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.

11. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2010, FirstEnergy's unrestricted retained earnings were $4.6 billion. Dividends declared in 2010 and 2009 were $2.20 per share in each year, which included quarterly dividends of $0.55 per share paid in the second, third and fourth quarters of 2010 and 2009, respectively, and payable in the first quarter of 2011 and 2010, respectively. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. The articles of incorporation, indentures and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy as of December 31, 2010.

(B) PREFERRED AND PREFERENCE STOCK

FirstEnergy's and the Utilities' preferred stock and preference stock authorizations are as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$100		
OE	6,000,000	$100	8,000,000	no par
OE	8,000,000	$25		
Penn	1,200,000	$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$100	5,000,000	$25
TE	12,000,000	$25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		

No preferred shares or preference shares are currently outstanding.

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following table presents the outstanding consolidated long-term debt and other long-term obligations of FirstEnergy as of December 31, 2010 and 2009:

	Weighted Average Interest Rate (%)	December 31, 2010	2009
		(in millions)	
FMBs:			
Due 2010-2013	9.74	$ 3	$ 28
Due 2014-2018	8.84	330	330
Due 2019-2023	6.13	101	107
Due 2024-2028	8.75	314	314
Due 2038	8.25	275	275
Total FMBs		1,023	1,054
Secured Notes:			
Due 2010-2013	4.46	732	456
Due 2014-2018	6.87	638	777
Due 2019-2023	5.60	622	481
Due 2029-2033	5.41	276	510
Due 2034-2038	4.13	459	322
Due 2041	0.30	57	57
Total Secured Notes		2,784	2,603
Unsecured Notes:			
Due 2010-2013	5.80	712	878
Due 2014-2018	5.43	2,467	2,473
Due 2019-2023	5.72	2,435	2,435
Due 2024-2028	3.95	65	65
Due 2029-2033	6.25	1,971	1,737
Due 2034-2038	5.47	1,727	1,864
Due 2039-2043	5.25	698	698
Due 2047	3.00	46	46
Total Unsecured Notes		10,121	10,196
Capital lease obligations		54	13
Net unamortized premium (discount) on debt		83	(24)
Long-term debt due within one year		(1,486)	(1,834)
Total long-term debt and other long term obligations		$ 12,579	$ 12,008

Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the accounts of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS.

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. As of December 31, 2010, $310 million of the transition bonds were outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628,000 that are payable from TBC collections.

Other Long-term Debt

FGCO, NGC and each of the Utilities, except for JCP&L and Penelec, have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. There also exist cross-default provisions in a number of the respective financing arrangements of FirstEnergy, FES, FGCO, NGC and the Utilities. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries defaults under another financing arrangement of a certain principal amount, typically $50 million. Although such defaults by any of the Utilities will generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by FirstEnergy will not generally cross-default applicable financing arrangements of any of the Utilities. Defaults by any of FES, FGCO or NGC will generally cross-default to applicable financing arrangements of FirstEnergy and, due to the existence of guarantees of FirstEnergy of certain financing arrangements of FES, FGCO and NGC, defaults by FirstEnergy will generally cross-default FES, FGCO and NGC financing arrangements containing these provisions. Cross-default provisions are not typically found in any of the senior note or FMBs of FirstEnergy or the Utilities.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2010, the Utilities' annual sinking fund requirement for all FMB issued under the various mortgage indentures amounted to payments of $36 million (Penn - $7 million, Met-Ed - $8 million, and Penelec - $21 million) in 2010. Penn expects to meet its 2011 annual sinking fund requirement with a replacement credit under its mortgage indenture. Met-Ed can fulfill its sinking fund obligation by providing bondable property additions, previously retired FMBs or cash to the respective mortgage bond trustees. Since Penelec's first mortgage bond indenture was terminated in 2010, Penelec no longer has a sinking fund obligation.

As of December 31, 2010, FirstEnergy's currently payable long-term debt includes approximately $827 million (FES - $778 million, Met-Ed - $29 million and Penelec - $20 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

On August 20, 2010, FES completed the remarketing of $250 million of PCRBs. Of the $250 million, $235 million of PCRBs were converted from a variable interest rate to a fixed interest rate. The remaining $15 million of PCRBs continue to bear a fixed interest rate. The interest rate conversion minimizes financial risk by converting the long-term debt into a fixed rate and, as a result, reducing exposure to variable interest rates over the short-term. These remarketings included two series: $235 million of PCRBs that now bears a per-annum rate of 2.25% and is subject to mandatory purchase on June 3, 2013; and $15 million of PCRBs that now bears a per-annum rate of 1.5% and is subject to mandatory purchase on June 1, 2011.

On October 1, 2010, FES completed the refinancing and remarketing of six series of PCRBs totaling $313 million. These PCRBs were converted from a variable interest rate to a fixed long term interest rate of 3.375% per annum and are subject to mandatory purchase on July 1, 2015.

On December 3, 2010, FES completed the remarketing of four series of PCRBs totaling $153 million and Penelec completed the remarketing of one $25 million PCRB. These PCRBs were converted from a variable interest rate to fixed interest rates ranging from 2.25% to 3.75% per annum.

Sinking fund requirements for FMBs and maturing long-term debt (excluding capital leases and variable rate PCRBs) for the next five years are:

Year	FE	FES	OE	CEI	JCP&L	Met-Ed	Penelec
				(In millions)			
2011	$ 445	$ 163	$ 1	$ 20	$ 32	$ -	$ -
2012	448	68	1	22	34	-	-
2013	554	75	1	324	36	150	-
2014	529	99	1	26	38	250	150
2015	639	450	151	24	41	-	-

The following table classifies the outstanding PCRBs by year, for the next three years, representing the next time the debt holders may exercise their right to tender their PCRBs.

Year	FE	FES	Met-Ed	Penelec
		(In millions)		
2011	$ 1,043	$ 969	$ 29	$ 45
2012	270	270	-	-
2013	235	235	-	-

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs of $835 million as of December 31, 2010, or noncancelable municipal bond insurance of $14 million as of December 31, 2010, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs or the insurance, FGCO, NGC and the Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Utilities pay annual fees of 0.35% to 3.30% of the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations. OE has LOCs of $130 million and $42 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. The amounts and annual fees for FirstEnergy, FES and the Utilities are as follows:

	FE	FES	Met-Ed	Penelec
		(In millions)		
Amounts				
LOCs	$ 835	$ 786	$ 29	$ 20
Insurance Policies	14	-	14	-
Annual Fee				
LOCs	0.35% to 3.30%	0.35% to 3.30%	1.60%	1.60%

12. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation).

The ARO liabilities for FES, OE and TE primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities (OE for its leasehold interest in Beaver Valley Unit 2 and Perry and TE for its leasehold interest in Beaver Valley Unit 2). The ARO liabilities for JCP&L, Met-Ed and Penelec primarily relate to the decommissioning of the TMI-2 nuclear generating facility. FES and the Utilities use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy, FES and the Utilities maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2010 and 2009 were as follows:

	2010	2009
	(In millions)	
FE	$ 1,973	$ 1,859
FES	1,146	1,089
OE	127	121
TE	76	74
JCP&L	182	167
Met-Ed	289	266
Penelec	153	143

Accounting standards for conditional retirement obligations associated with tangible long-lived assets require recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not in the recognition of the liability.

The following table summarizes the changes to the ARO balances during 2010 and 2009.

ARO Reconciliation	FE	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)				
Balance, January 1, 2009	$ 1,347	$ 863	$ 92	$ 2	$ 30	$ 95	$ 171	$ 87
Liabilities incurred	4	1	-	-	-	-	-	-
Liabilities settled	-	-	-	-	-	-	-	-
Accretion	90	58	6	-	2	7	11	6
Revisions in estimated cash flows	(16)	(1)	(12)	-	-	-	(2)	(1)
Balance, December 31, 2009	1,425	921	86	2	32	102	180	92
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	(11)	-	(10)	-	-	-	-	-
Accretion	93	59	5	-	2	6	13	6
Revisions in estimated cash flows [1]	(100)	(88)	(7)	-	(5)	-	-	-
Balance, December 31, 2010	$ 1,407	$ 892	$ 74	$ 2	$ 29	$ 108	$ 193	$ 98

[1] During the second quarter of 2010, studies were completed to reassess the estimated cost of decommissioning the Beaver Valley nuclear generating facilities. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES, OE and TE and reduced the liability for each subsidiary in the amounts of $88 million, $7 million, and $5 million, respectively.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately $700 million of short-term indebtedness as of December 31, 2010, comprised of borrowings under a $2.75 billion revolving line of credit. Total short-term bank lines of committed credit to FirstEnergy and the Utilities as of January 31, 2011 were approximately $3.2 billion of which $2.5 billion was unused and available.

FirstEnergy, along with certain of its subsidiaries, are parties 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%.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2010:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(in millions)	
FirstEnergy	$ 2,750	$ - (1)
FES	1,000	- (1)
OE	500	500
Penn	50	34 (2)
CEI	250 (3)	500
TE	250 (3)	500
JCP&L	425	411 (2)
Met-Ed	250	300 (2)
Penelec	250	300 (2)
ATSI	50 (4)	100

(1) No regulatory approvals, statutory or charter limitations applicable.
(2) Excluding amounts which may be borrowed under the regulated companies' money pool.
(3) Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at least BBB by S&P and Baa2 by Moody's.
(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

The regulated companies also have the ability to borrow from each other and FirstEnergy to meet their short-term working capital requirements. A similar but separate arrangement exists among the unregulated companies. FESC administers these two money pools and tracks FirstEnergy's surplus funds and those of the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2010 was 0.51% for the regulated companies' money pool and 0.60% for the unregulated companies' money pool.

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2010 and 2009 were as follows:

	2010	2009
FE	0.68 %	0.74 %
FES	0.60 %	1.84 %
OE	0.51 %	0.72 %
CEI	1.92 %	1.13 %
TE	-	0.72 %
JCP&L	-	-
Met-Ed	0.51 %	-
Penelec	0.51 %	0.72 %

As of December 31, 2010, FirstEnergy Corp. had four receivables securitizations for five of its seven public utilities. These transactions enable the company to access up to $395 million of financing at costs based on commercial paper rates plus annual fees. Each of the facilities matures in 364 days, and are reflected in the table below. In March of 2011 the Centerior Funding Corp. and OES Capital facilities are scheduled to decrease to $100 million each. There were no outstanding borrowings as of December 31, 2010.

Subsidiary Company	Parent Company	Commitment	Annual Facility Fee	Maturity
		(In millions)		
OES Capital, Incorporated	OE	$ 125	1.08 %	March 30, 2011
Centerior Funding Corporation	CEI	125	1.00	March 30, 2011
Met-Ed Funding LLC	Met-Ed	75	0.51	June 17, 2011
Penelec Funding LLC	Penelec	70	0.51	June 17, 2011
		$ 395		

14. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) 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).

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.

(B) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of December 31, 2010, outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting primarily of parental guarantees ($0.8 billion), subsidiaries' guarantees ($2.5 billion), surety bonds and LOCs ($0.4 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.3 billion (included in the $0.8 billion discussed above) as of December 31, 2010 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2010, FirstEnergy's maximum exposure under these collateral provisions was $468 million, consisting of $429 million due to a below investment grade credit rating (of which $224 million is due to an acceleration of payment or funding obligation) and $39 million due to "material adverse event" contractual clauses. Additionally, stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase this amount to $532 million, consisting of $486 million due to a below investment grade credit rating (of which $224 million is related to an acceleration of payment or funding obligation) and $46 million due to "material adverse event" contractual clauses.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $82 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' power portfolio as of December 31, 2010, and forward prices as of that date, FES has posted collateral of $185 million. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $28 million. Depending on the volume of forward contracts and future price movements, FES could be required to post higher amounts for margining.

In connection with FES' obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

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

On October 22, 2010, Signal Peak and Global Rail entered into a $350 million syndicated two-year senior secured term loan facility among the two limited liability companies that comprise Signal Peak and Global Rail, as borrowers. FirstEnergy, together with WMB Loan Ventures LLC and WMB Loan Ventures II LLC, the entities that share ownership with FEV, the borrowers have provided a guaranty of the borrowers' obligations under the facility. In addition, FEV and the other entities that directly own the equity interest in the borrowers have pledged those interests to the banks as collateral for the facility.

(C) 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.

(D) OTHER LEGAL PROCEEDINGS

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages due to the outages. After various motions, rulings and appeals, the Plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, strict product liability and punitive damages were dismissed, leaving only the negligence and breach of contract causes of actions. On July 29, 2010, the Appellate Division upheld the trial court's decision decertifying the class. Plaintiffs have filed, and JCP&L has opposed, a motion for leave to appeal to the New Jersey Supreme Court. JCP&L is waiting for the Court's decision.

Litigation Relating to the Proposed Allegheny Merger

In connection with the proposed merger (Note 22), purported shareholders of Allegheny have filed putative shareholder class action and/or derivative lawsuits against Allegheny and its directors and certain officers, referred to as the Allegheny Energy defendants, FirstEnergy and Merger Sub. Four putative class action and derivative lawsuits were filed in the Circuit Court for Baltimore City, Maryland (Maryland Court). One was withdrawn. The Maryland Court has consolidated the remaining three cases under the caption: In re Allegheny Energy Shareholder and Derivative Litigation, C.A. No. 24-C-10-1301. Three shareholder lawsuits were filed in the Court of Common Pleas of Westmoreland County, Pennsylvania and the court has consolidated these actions under the caption: In re Allegheny Energy, Inc. Shareholder Class and Derivative, Litigation, Lead Case No. 1101 of 2010. One putative shareholder class action was filed in the U.S. District Court for the Western District of Pennsylvania and is captioned Louisiana Municipal Police Employees' Retirement System v. Evanson, et al., C.A. No. 10-319 NBF. In summary, the lawsuits allege, among other things, that the Allegheny Energy directors breached their fiduciary duties by approving the merger agreement, and that Allegheny, FirstEnergy and Merger Sub aided and abetted in these alleged breaches of fiduciary duty. The complaints seek, among other things, jury trials, money damages and injunctive relief. While FirstEnergy believes the lawsuits are without merit and has defended vigorously against the claims, in order to avoid the costs associated with the litigation, the defendants have agreed to the terms of a disclosure-based settlement of all these shareholder lawsuits and have reached agreement with counsel for all of the plaintiffs concerning fee applications. Under the terms of the settlement, no payments are being made by FirstEnergy or Merger Sub. A formal stipulation of settlement was filed with the Maryland Court on October 18, 2010 and it was approved and became final on January 12, 2011. The separate Pennsylvania federal and state proceedings were dismissed on January 14, 2011 and January 18, 2011, respectively. The above shareholder actions have been fully and finally resolved.

Nuclear Plant Matters

During a planned refueling outage that began on February 28, 2010, FENOC conducted a non destructive examination and testing of the CRDM nozzles of the Davis-Besse reactor pressure vessel head. FENOC identified flaws in CRDM nozzles that required modification. The NRC was notified of these findings, along with federal, state and local officials. On March 17, 2010, the NRC sent a special inspection team to Davis-Besse to assess the adequacy of FENOC's identification, analyses and resolution of the CRDM nozzle flaws and to ensure acceptable modifications were made prior to placing the RPV head back in service. After successfully completing the modifications, FENOC committed to take a number of corrective actions including strengthening leakage monitoring procedures and shutting Davis-Besse down no later than October 1, 2011, to replace the reactor pressure vessel head with nozzles made of material less susceptible to primary water stress corrosion cracking, further enhancing the safe and reliable operations of the plant. On June 29, 2010, FENOC returned Davis-Besse to service. On September 9, 2010, the NRC held a public exit meeting describing the results of the NRC special inspection team inspection of FENOC's identification of the CRDM nozzles with flaws and the modifications to those nozzles. On October 22, 2010, the NRC issued its final report of the special inspection. The report contained three findings characterized as very low safety significance that were promptly corrected prior to plant operation.

On April 5, 2010, the Union of Concerned Scientists (UCS) requested that the NRC issue a Show Cause Order, or otherwise delay the restart of the Davis-Besse Nuclear Power Station until the NRC determines that adequate protection standards have been met and reasonable assurance exists that these standards will continue to be met after the plant's operation is resumed. By a letter dated July 13, 2010, the NRC denied UCS's request for immediate action because "the NRC has conducted rigorous and independent assessments of returning the Davis-Besse reactor vessel head to service and its continued operation, and determined that it was safe for the plant to restart." The UCS petition was referred to a petition manager for further review. What additional actions, if any, that the NRC takes in response to the UCS request have not been determined.

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 issued guidance anticipating an increase in low-level radioactive waste disposal costs associated 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.

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.

Ohio Legal Matters

On February 16, 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount was approved by the PUCO. On March 18, 2010, the named-defendant companies filed a motion to dismiss the case due to the lack of jurisdiction of the court of common pleas. The court granted the motion to dismiss on September 7, 2010. The plaintiffs appealed the decision to the Court of Appeals of Ohio, which has not yet rendered an opinion.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described below.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

15. SEGMENT INFORMATION

Financial information for each of FirstEnergy's reportable segments is presented in the following table. FES and the Utilities do not have separate reportable operating segments.

The Energy Delivery Services segment transmits and distributes electricity through FirstEnergy's eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey, and purchases power for its POLR and default service requirements in Ohio, Pennsylvania and New Jersey. Its revenues are primarily derived from the delivery of electricity within FirstEnergy's service areas, cost recovery of regulatory assets 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 purchased power costs.

The Competitive Energy Services segment supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the POLR and default service requirements of FirstEnergy's Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Maryland, Michigan and New Jersey. This business segment controls approximately 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.

The other segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment.

Segment Financial Information

For the Years Ended December 31,		Energy Delivery Services		Competitive Energy Services		Other		Reconciling Adjustments		Consolidated
						(In millions)				
2010										
External revenues	$	9,813	$	3,544	$	33	$	(125)	$	13,265
Internal revenues*		139		2,301		-		(2,366)		74
		9,952		5,845		33		(2,491)		13,339
Depreciation and amortization		1,173		254		32		9		1,468
Investment income		102		51		1		(37)		117
Net interest charges		491		129		6		54		680
Income taxes		372		158		(13)		(35)		482
Net income		607		258		(4)		(101)		760
Total assets		22,613		11,240		618		334		34,805
Total goodwill		5,551		24		-		-		5,575
Property additions		745		1,129		24		65		1,963
2009										
External revenues	$	11,144	$	1,894	$	37	$	(119)	$	12,956
Internal revenues*		-		2,843		-		(2,826)		17
		11,144		4,737		37		(2,945)		12,973
Depreciation and amortization		1,464		270		10		11		1,755
Investment income		139		121		-		(56)		204
Net interest charges		469		106		8		265		848
Income taxes		290		345		(265)		(125)		245
Net income		435		517		257		(219)		990
Total assets		22,978		10,584		607		135		34,304
Total goodwill		5,551		24		-		-		5,575
Property additions		750		1,262		149		42		2,203
2008										
External revenues	$	12,068	$	1,571	$	72	$	(84)	$	13,627
Internal revenues		-		2,968		-		(2,968)		-
		12,068		4,539		72		(3,052)		13,627
Depreciation and amortization		1,154		243		4		13		1,414
Investment income		171		(34)		6		(84)		59
Net interest charges		408		108		2		184		702
Income taxes		611		314		(53)		(95)		777
Net income		916		472		116		(165)		1,339
Total assets		23,025		9,559		539		398		33,521
Total goodwill		5,551		24		-		-		5,575
Property additions		839		1,835		176		38		2,888

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

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

Products and Services

Year		Electricity Sales
		(in millions)
2010	$	12,523
2009		12,032
2008		12,693

16. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In 2010, the FASB Emerging Issues Task Force amended the Goodwill and Other Topic of the FASB Accounting Standards Codification. The amendment requires entities with a zero or negative carrying value to assess whether it is more likely than not that a goodwill impairment exists through the consideration of qualitative factors. If an entity concludes that it is more likely than not that a goodwill impairment exists, the entity must perform step 2 of the goodwill impairment test. The amendment is effective for fiscal years, and interim periods within those years, beginning after December 15, 2010. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In 2010, the FASB Emerging Issues Task Force amended the Business Combinations Topic of the FASB Accounting Standards Codification. The amendment addresses how entities prepare pro forma financial information as a result of a business combination. Under the amendment, if comparative financial statements are presented an entity should present the pro forma disclosures as if the business combination occurred at the beginning of the prior annual period. An entity must provide additional disclosures describing the nature and amount of material, nonrecurring pro forma adjustments. The amendment is effective for business combinations consummated in periods beginning after December 15, 2010. FirstEnergy will implement the amendment to Business Combinations guidance for acquisitions consummated after January 1, 2011.

17. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' and the Utilities' operating revenues, operating expenses, investment income and interest expense include transactions with affiliated companies. These affiliated company transactions include PSAs between FES and the Utilities, support service billings from FESC and FENOC, interest on associated company notes and other transactions (see Note 7).

The Ohio Companies had a full requirements PSA with FES through December 31, 2008 to meet their POLR and default service obligations. Met-Ed and Penelec had a partial requirement PSA with FES to meet a portion of their POLR and default service obligations through the end of 2010 (see Note 9). FES is incurring interest expense through FGCO and NGC on associated company notes payable to the Ohio Companies and Penn related to the 2005 intra-system generation asset transfers. The primary affiliated company transactions for FES and the Utilities during the three years ended December 31, 2010 are as follows:

Affiliated Company Transactions - 2010	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,227	$ 190	$ 2	$ 46	$ -	$ 73	$ 65
Ground lease with ATSI	-	12	7	2	-	-	-
Other	88	1	7	1	-	10	-
Expenses:							
Purchased power from affiliates	371	521	361	181	-	612	643
Fuel	46	-	-	-	-	-	-
Support services	620	128	64	52	94	59	58
Investment Income:							
Interest income from affiliates	-	-	-	12	-	-	-
Interest income from FirstEnergy	3	-	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	9	3	14	1	4	2	2
Interest expense to FirstEnergy	-	-	1	-	-	-	-

Affiliated Company Transactions - 2009	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,826	$ 189	$ 2	$ 38	$ -	$ -	$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Other	30	1	6	1	-	10	-
Expenses:							
Purchased power from affiliates	222	991	735	393	-	365	342
Fuel	15	-	-	-	-	-	-
Support services	584	141	62	59	91	54	57
Investment Income:							
Interest income from affiliates	-	15	-	17	-	-	-
Interest income from FirstEnergy	4	1	-	-	-	1	-
Interest Expense:							
Interest expense to affiliates	6	5	17	2	4	3	2
Interest expense to FirstEnergy	4	1	1	1	-	-	1

Affiliated Company Transactions - 2008	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Revenues:							
Electric sales to affiliates	$ 2,968	$ 75	$ 6	$ 32	$ -	$ -	$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Other	6	1	12	3	1	10	1
Expenses:							
Purchased power from affiliates	101	1,203	766	411	-	304	284
Fuel	5	-	-	-	-	-	-
Support services	584	146	69	71	95	57	59
Investment Income:							
Interest income from affiliates	1	15	1	20	1	-	1
Interest income from FirstEnergy	12	13	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	4	3	19	1	3	2	2
Interest expense to FirstEnergy	26	-	7	2	5	4	5

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

18. SUPPLEMENTAL GUARANTOR INFORMATION

As discussed in Note 7, FES has fully and unconditionally guaranteed all of FGCO's obligations under each of the leases associated with Bruce Mansfield Unit 1. The Consolidating Statements of Income for the three years ended December 31, 2010, Consolidating Balance Sheets as of December 31, 2010, and December 31, 2009, and Condensed Consolidating Statements of Cash Flows for the three years ended December 31, 2010, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved (see Note 7). The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 5,665,077	$ 2,435,027	$ 1,567,728	$ (3,840,218)	$ 5,827,614
EXPENSES:					
Fuel	30,618	1,200,432	171,789	-	1,402,839
Purchased power from affiliates	3,948,399	30,496	232,015	(3,840,218)	370,692
Purchased power from non-affiliates	1,585,207	-	-	-	1,585,207
Other operating expenses	315,767	377,534	537,281	48,758	1,279,340
Provision for depreciation	3,083	99,386	146,051	(5,224)	243,296
General taxes	23,869	42,337	27,571	-	93,777
Impairment of long-lived assets	-	383,665	-	-	383,665
Total expenses	5,906,943	2,133,850	1,114,707	(3,796,684)	5,358,816
OPERATING INCOME (LOSS)	(241,866)	301,177	453,021	(43,534)	468,798
OTHER INCOME (EXPENSE):					
Investment income	4,679	908	53,615	-	59,202
Miscellaneous income, including net income from equity investees	485,467	647	56	(469,503)	16,667
Interest expense - affiliates	(240)	(7,830)	(1,685)	-	(9,755)
Interest expense - other	(95,825)	(108,543)	(65,385)	63,653	(206,100)
Capitalized interest	399	74,655	16,619	-	91,673
Total other income (expense)	394,480	(40,163)	3,220	(405,850)	(48,313)
INCOME BEFORE INCOME TAXES	152,614	261,014	456,241	(449,384)	420,485
INCOME TAXES (BENEFITS)	(116,814)	81,621	167,435	18,815	151,057
NET INCOME	$ 269,428	$ 179,393	$ 288,806	$ (468,199)	$ 269,428

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 4,390,111	$ 2,216,237	$ 1,360,522	$ (3,238,533)	$ 4,728,337
EXPENSES:					
Fuel	18,416	971,021	138,026	-	1,127,463
Purchased power from affiliates	3,220,197	18,336	222,406	(3,238,533)	222,406
Purchased power from non-affiliates	996,383	-	-	-	996,383
Other operating expenses	220,660	395,330	518,473	48,762	1,183,225
Provision for depreciation	4,147	121,007	139,488	(5,249)	259,393
General taxes	18,214	44,075	24,626	-	86,915
Impairment of long-lived assets	-	6,067	-	-	6,067
Total expenses	4,478,017	1,555,836	1,043,019	(3,195,020)	3,881,852
OPERATING INCOME (LOSS)	(87,906)	660,401	317,503	(43,513)	846,485
OTHER INCOME (EXPENSE):					
Investment income	5,297	683	119,246	-	125,226
Miscellaneous income (expense), including net income from equity investees	656,451	2,136	61	(645,911)	12,737
Interest expense - affiliates	(135)	(5,619)	(4,352)	-	(10,106)
Interest expense - other	(44,837)	(99,802)	(62,034)	64,553	(142,120)
Capitalized interest	212	49,577	10,363	-	60,152
Total other income (expense)	616,988	(53,025)	63,284	(581,358)	45,889
INCOME BEFORE INCOME TAXES	529,082	607,376	380,787	(624,871)	892,374
INCOME TAXES (BENEFITS)	(48,002)	207,171	135,785	20,336	315,290
NET INCOME	$ 577,084	$ 400,205	$ 245,002	$ (645,207)	$ 577,084

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

For the Year Ended December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 4,470,112	$ 2,275,451	$ 1,204,534	$ (3,431,744)	$ 4,518,353
EXPENSES:					
Fuel	16,322	1,171,993	126,978	-	1,315,293
Purchased power from affiliates	3,417,126	14,618	101,409	(3,431,744)	101,409
Purchased power from non-affiliates	778,882	-	-	-	778,882
Other operating expenses	116,972	416,723	502,096	48,757	1,084,548
Provision for depreciation	5,986	119,763	111,529	(5,379)	231,899
General taxes	19,260	46,153	22,591	-	88,004
Total expenses	4,354,548	1,769,250	864,603	(3,388,366)	3,600,035
OPERATING INCOME	115,564	506,201	339,931	(43,378)	918,318
OTHER INCOME (EXPENSE):					
Investment income	10,953	2,034	(35,665)	-	(22,678)
Miscellaneous income (expense), including net income from equity investees	438,214	(5,400)	-	(431,116)	1,698
Interest expense to affiliates	(314)	(20,342)	(9,173)	-	(29,829)
Interest expense - other	(24,674)	(95,926)	(56,486)	65,404	(111,682)
Capitalized interest	142	39,934	3,688	-	43,764
Total other income (expense)	424,321	(79,700)	(97,636)	(365,712)	(118,727)
INCOME BEFORE INCOME TAXES	539,885	426,501	242,295	(409,090)	799,591
INCOME TAXES	33,475	155,100	90,247	14,359	293,181
NET INCOME	$ 506,410	$ 271,401	$ 152,048	$ (423,449)	$ 506,410

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING BALANCE SHEETS

As of December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ -	$ 9,273	$ 8	$ -	$ 9,281
Receivables-					
Customers	365,758	-	-	-	365,758
Associated companies	333,323	356,564	125,716	(338,038)	477,565
Other	21,010	55,758	12,782	-	89,550
Notes receivable from associated companies	34,331	188,796	173,643	-	396,770
Materials and supplies, at average cost	40,713	276,149	228,480	-	545,342
Derivatives	181,660	-	-	-	181,660
Prepayments and other	47,712	11,352	1,107	-	60,171
	1,024,507	897,892	541,736	(338,038)	2,126,097
PROPERTY, PLANT AND EQUIPMENT:					
In service	96,371	6,197,776	5,411,852	(384,681)	11,321,318
Less - Accumulated provision for depreciation	17,039	2,020,463	2,162,173	(175,395)	4,024,280
	79,332	4,177,313	3,249,679	(209,286)	7,297,038
Construction work in progress	8,809	519,651	534,284	-	1,062,744
	88,141	4,696,964	3,783,963	(209,286)	8,359,782
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,145,846	-	1,145,846
Investment in associated companies	4,941,763	-	-	(4,941,763)	-
Other	374	11,128	202	-	11,704
	4,942,137	11,128	1,146,048	(4,941,763)	1,157,550
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	42,986	412,427	-	(455,413)	-
Customer intangibles	133,968	-	-	-	133,968
Goodwill	24,248	-	-	-	24,248
Property taxes	-	16,463	24,649	-	41,112
Unamortized sale and leaseback costs	-	10,828	-	62,558	73,386
Derivatives	97,603	-	-	-	97,603
Other	21,018	70,810	14,463	(57,602)	48,689
	319,823	510,528	39,112	(450,457)	419,006
	$ 6,374,608	$ 6,116,512	$ 5,510,859	$ (5,939,544)	$ 12,062,435
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 100,775	$ 418,832	$ 632,106	$ (19,578)	$ 1,132,135
Short-term borrowings-					
Associated companies	-	11,561	-	-	11,561
Accounts payable-					
Associated companies	351,172	212,620	249,820	(346,989)	466,623
Other	139,037	102,154	-	-	241,191
Accrued taxes	3,358	36,187	30,726	(142)	70,129
Derivatives	266,411	-	-	-	266,411
Other	51,619	147,754	15,156	37,142	251,671
	912,372	929,108	927,808	(329,567)	2,439,721
CAPITALIZATION:					
Total equity	3,788,245	2,514,775	2,413,580	(4,928,859)	3,787,741
Long-term debt and other long-term obligations	1,518,586	2,118,791	793,250	(1,249,752)	3,180,875
	5,306,831	4,633,566	3,206,830	(6,178,611)	6,968,616
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	959,154	959,154
Accumulated deferred income taxes	-	-	448,115	(390,520)	57,595
Accumulated deferred investment tax credits	-	33,280	20,944	-	54,224
Asset retirement obligations	-	26,780	865,271	-	892,051
Retirement benefits	48,214	236,946	-	-	285,160
Property taxes	-	16,463	24,649	-	41,112
Lease market valuation liability	-	216,695	-	-	216,695
Other	107,191	23,674	17,242	-	148,107
	155,405	553,838	1,376,221	568,634	2,654,098
	$ 6,374,608	$ 6,116,512	$ 5,510,859	$ (5,939,544)	$ 12,062,435

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING BALANCE SHEETS

As of December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ -	$ 3	$ 9	$ -	$ 12
Receivables-					
Customers	195,107	-	-	-	195,107
Associated companies	305,298	175,730	134,841	(297,308)	318,561
Other	28,394	10,960	12,518	-	51,872
Notes receivable from associated companies	416,404	240,836	147,863	-	805,103
Materials and supplies, at average cost	17,265	307,079	215,197	-	539,541
Derivatives	31,485	-	-	-	31,485
Prepayments and other	48,540	18,356	9,401	-	76,297
	1,042,493	752,964	519,829	(297,308)	2,017,978
PROPERTY, PLANT AND EQUIPMENT:					
In service	90,474	5,478,346	5,174,835	(386,023)	10,357,632
Less - Accumulated provision for depreciation	13,649	2,778,320	1,910,701	(171,512)	4,531,158
	76,825	2,700,026	3,264,134	(214,511)	5,826,474
Construction work in progress	6,032	2,049,078	368,336	-	2,423,446
	82,857	4,749,104	3,632,470	(214,511)	8,249,920
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,088,641	-	1,088,641
Investment in associated companies	4,477,602	-	-	(4,477,602)	-
Other	1,137	21,127	202	-	22,466
	4,478,739	21,127	1,088,843	(4,477,602)	1,111,107
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	93,379	381,849	-	(388,602)	86,626
Customer intangibles	16,566	-	-	-	16,566
Goodwill	24,248	-	-	-	24,248
Property taxes	-	27,811	22,314	-	50,125
Unamortized sale and leaseback costs	-	16,454	-	56,099	72,553
Derivatives	28,368	-	-	-	28,368
Other	54,477	71,179	18,755	(51,114)	93,297
	217,038	497,293	41,069	(383,617)	371,783
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 736	$ 646,402	$ 922,429	$ (18,640)	$ 1,550,927
Short-term borrowings-					
Associated companies	-	9,237	-	-	9,237
Accounts payable-					
Associated companies	261,788	170,446	295,045	(261,201)	466,078
Other	51,722	193,641	-	-	245,363
Accrued taxes	44,213	61,055	22,777	(44,887)	83,158
Derivatives	125,609	-	-	-	125,609
Other	47,406	132,314	16,734	36,994	233,448
	531,474	1,213,095	1,256,985	(287,734)	2,713,820
CAPITALIZATION:					
Common stockholder's equity	3,514,571	2,346,515	2,119,488	(4,466,003)	3,514,571
Long-term debt and other long-term obligations	1,619,339	1,906,818	554,825	(1,269,330)	2,811,652
	5,133,910	4,253,333	2,674,313	(5,735,333)	6,326,223
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	992,869	992,869
Accumulated deferred income taxes	-	-	342,840	(342,840)	-
Accumulated deferred investment tax credits	-	36,359	22,037	-	58,396
Asset retirement obligations	-	25,714	895,734	-	921,448
Retirement benefits	33,144	170,891	-	-	204,035
Property taxes	-	27,811	22,314	-	50,125
Lease market valuation liability	-	262,200	-	-	262,200
Other	122,599	31,085	67,988	-	221,672
	155,743	554,060	1,350,913	650,029	2,710,745
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (259,812)	$ 379,829	$ 684,745	$ (18,640)	$ 786,122
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	-	318,520	396,850	-	715,370
Short-term borrowings, net	-	2,324	-	-	2,324
Redemptions and Repayments-					
Long-term debt	(804)	(341,542)	(448,748)	18,640	(772,454)
Other	(460)	(750)	(930)	-	(2,140)
Net cash used for financing activities	(1,264)	(21,448)	(52,828)	18,640	(56,900)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(8,367)	(518,731)	(507,587)	-	(1,034,685)
Proceeds from asset sales	-	117,333	-	-	117,333
Sales of investment securities held in trusts	-	-	1,926,684	-	1,926,684
Purchases of investment securities held in trusts	-	-	(1,974,020)	-	(1,974,020)
Loans from (to) associated companies, net	382,073	52,040	(25,780)	-	408,333
Customer acquisition costs	(113,336)	-	-	-	(113,336)
Leasehold improvement payments to associated companies	-	-	(51,204)	-	(51,204)
Other	706	247	(11)	-	942
Net cash provided from (used for) investing activities	261,076	(349,111)	(631,918)	-	(719,953)
Net change in cash and cash equivalents	-	9,270	(1)	-	9,269
Cash and cash equivalents at beginning of period	-	3	9	-	12
Cash and cash equivalents at end of period	$ -	$ 9,273	$ 8	$ -	$ 9,281

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (20,027)	$ 790,411	$ 621,649	$ (17,744)	$ 1,374,289
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	1,498,087	576,800	363,515	-	2,438,402
Equity contributions from parent	-	100,000	150,000	(250,000)	-
Redemptions and Repayments-					
Long-term debt	(1,766)	(320,754)	(404,383)	17,747	(709,156)
Short-term borrowings, net	(901,119)	(248,120)	(6,347)	-	(1,155,586)
Other	(12,054)	(6,157)	(3,576)	(3)	(21,790)
Net cash provided from financing activities	583,148	101,769	99,209	(232,256)	551,870
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(4,372)	(671,691)	(546,869)	-	(1,222,932)
Proceeds from asset sales	-	18,371	-	-	18,371
Sales of investment securities held in trusts	-	-	1,379,154	-	1,379,154
Purchases of investment securities held in trusts	-	-	(1,405,996)	-	(1,405,996)
Loans to associated companies, net	(309,175)	(218,890)	(147,863)	-	(675,928)
Investment in subsidiary	(250,000)	-	-	250,000	-
Other	426	(20,006)	725	-	(18,855)
Net cash used for investing activities	(563,121)	(892,216)	(720,849)	250,000	(1,926,186)
Net change in cash and cash equivalents	-	(36)	9	-	(27)
Cash and cash equivalents at beginning of period	-	39	-	-	39
Cash and cash equivalents at end of period	$ -	$ 3	$ 9	$ -	$ 12

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM OPERATING ACTIVITIES	$ 40,791	$ 350,986	$ 478,047	$ (16,896)	$ 852,928
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	-	353,325	265,050	-	618,375
Equity contributions from parent	280,000	675,000	175,000	(850,000)	280,000
Short-term borrowings, net	701,119	18,571	-	(18,931)	700,759
Redemptions and Repayments-					
Long-term debt	(2,955)	(293,349)	(183,132)	16,896	(462,540)
Short-term borrowings, net	-	-	(18,931)	18,931	-
Common stock dividend payment	(43,000)	-	-	-	(43,000)
Other	-	(3,107)	(2,040)	-	(5,147)
Net cash provided from financing activities	935,164	750,440	235,947	(833,104)	1,088,447
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(43,244)	(1,047,917)	(744,468)	-	(1,835,629)
Proceeds from asset sales	-	23,077	-	-	23,077
Sales of investment securities held in trusts	-	-	950,688	-	950,688
Purchases of investment securities held in trusts	-	-	(987,304)	-	(987,304)
Loans to associated companies, net	(83,457)	(21,946)	69,012	-	(36,391)
Investment in subsidiary	(850,000)	-	-	850,000	-
Other	744	(54,601)	(1,922)	-	(55,779)
Net cash used for investing activities	(975,957)	(1,101,387)	(713,994)	850,000	(1,941,338)
Net change in cash and cash equivalents	(2)	39	-	-	37
Cash and cash equivalents at beginning of period	2	-	-	-	2
Cash and cash equivalents at end of period	$ -	$ 39	$ -	$ -	$ 39

19. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value.

Coal-Fired FGCO Units

On August 12, 2010, FirstEnergy announced its intention to make operational changes at certain coal-fired FGCO units. The announcement of the operational change indicated a need to evaluate the future recoverability of the carrying value of the assets associated with the affected FGCO units. As a result of the recoverability evaluation, FirstEnergy recorded an impairment of $303 million to continuing operations of its competitive energy services segment during the year ended December 31, 2010. This impairment represents a $296 million write down of the carrying value of the assets associated with the affected FGCO units to their estimated fair value and a charge of $7 million for excessive or obsolete inventory identified as a result of the operational changes.

FirstEnergy used various assumptions in evaluating whether the FGCO units' carrying value was recoverable. The estimated undiscounted cash flows were based on assumptions about budgeted net operating income; the impact of current market conditions on future revenues including a long-term view of future market prices; the impact of reduced customer demand; and the estimated cost of remedial retro-fitting of the FGCO units to comply with proposed changes in federal environmental laws. The result of this evaluation indicated that the carrying costs of the FGCO units were not fully recoverable.

FirstEnergy further evaluated the extent to which the carrying value of the FGCO units exceeded their estimated fair value. FirstEnergy applied the income approach to estimating fair value under a discounted cash flow valuation technique to convert future cash flows expected over the remaining life of the asset group to a single present value. The assumptions used to estimate the non-recurring fair value measurement of the FGCO units applied significant unobservable inputs considered Level 3 under the fair value hierarchy. The estimated cash flows used during the recoverability test were discounted using the weighted average cost of capital for a market participant.

Mad River

On November 10, 2010, a planned demolition of a 275-foot stack at FGCO's Mad River Plant resulted in the demolished stack falling in the wrong direction and destroying two generating units at the Mad River plant. The accident resulted in a $5 million write-off of the total carrying value of the assets associated with the destroyed units and a charge of $1 million for fuel oil inventory deemed to be excessive or obsolete as a result of the accident. FirstEnergy recorded an impairment of $6 million to continuing operations of its competitive energy services segment for the year ended December 31, 2010.

R.E. Burger Biomass Units

In 2010 FirstEnergy announced that it was canceling its plan to repower Units 4 and 5 at its R. E. Burger Plant to generate electricity principally with biomass, and instead permanently shut down the units as of December 31, 2010. Since the Burger biomass repowering project was announced, market prices for electricity have fallen significantly and no longer supported a repowered Burger Plant. FirstEnergy's announcement indicated a need to evaluate the future recoverability of the carrying value of the assets associated with the affected Burger units. As a result of the recoverability evaluation, FirstEnergy recorded an impairment of $72 million to continuing operations of its competitive energy services segment for the year ended December 31, 2010. This impairment represents a $69 million write down of the carrying value of the assets associated with the affected Burger units to their estimated fair value and a charge of $3 million for excessive or obsolete inventory identified as a result of the permanent shut down of the Burger units.

20. INTANGIBLE ASSETS

FES has acquired certain customer contract rights, which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts. Net intangible assets of $134 million are included in other assets on FirstEnergy's Consolidated Balance Sheet as of December 31, 2010.

The weighted-average amortization period of these certain customer contract rights as of December 31, 2010, is 9 years. For the year ended December 31, 2010, amortization expense was approximately $9 million. The expected estimated aggregate amortization expense for each of the next five years and for all years thereafter is as follows:

Future Amortization		
(In millions)		
2011	$	12
2012		14
2013		16
2014		17
2015		17
Years thereafter		58
Total amortization	$	134

21. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2010 and 2009.

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) Before Income Taxes	Income Taxes (Benefit)	Earnings Available To FirstEnergy
			(In millions)		
FE					
March 31, 2010	$ 3,299.0	$ 416.0	$ 260.0	$ 111.0	$ 155.0
March 31, 2009	3,334.0	346.0	169.0	54.0	119.0
June 30, 2010	3,128.0	526.0	390.0	134.0	265.0
June 30, 2009	3,271.0	802.0	656.0	248.0	414.0
September 30, 2010	3,693.0	415.0	294.0	119.0	179.0
September 30, 2009	3,408.0	487.0	358.0	128.0	234.0
December 31, 2010	3,219.0	448.0	298.0	118.0	185.0
December 31, 2009	2,960.0	244.0	52.0	(185.0)	239.0
FES					
March 31, 2010	$ 1,388.1	$ 154.5	$ 124.3	$ 44.4	$ 79.9
March 31, 2009	1,226.1	304.3	262.5	91.8	170.7
June 30, 2010	1,314.7	215.1	202.8	68.9	133.9
June 30, 2009	1,341.2	468.9	466.6	169.2	297.4
September 30, 2010	1,553.7	(47.7)	(42.1)	(5.4)	(36.7)
September 30, 2009	1,104.6	175.7	310.8	111.2	199.7
December 31, 2010	1,571.1	146.9	135.5	43.2	92.3
December 31, 2009	1,056.4	(102.4)	(147.5)	(56.9)	(90.7)
OE					
March 31, 2010	$ 508.4	$ 72.9	$ 55.8	$ 19.6	$ 36.0
March 31, 2009	749.0	30.2	15.7	4.0	11.5
June 30, 2010	439.4	63.4	49.2	11.9	37.2
June 30, 2009	672.2	58.8	50.5	16.9	33.5
September 30, 2010	486.6	90.1	75.6	29.3	46.1
September 30, 2009	602.5	52.8	50.6	15.9	34.6
December 31, 2010	401.7	74.0	58.6	21.2	37.4
December 31, 2009*	493.2	87.1	71.8	29.4	42.3
CEI					
March 31, 2010	$ 330.1	$ 50.3	$ 24.8	$ 10.8	$ 13.6
March 31, 2009	449.7	(144.1)	(166.9)	(61.5)	(105.9)
June 30, 2010	295.7	56.7	30.7	8.8	21.6
June 30, 2009	475.1	98.5	74.2	26.5	47.3
September 30, 2010	328.7	64.7	38.4	13.5	24.6
September 30, 2009	435.5	61.6	35.1	9.8	25.0
December 31, 2010	266.9	43.7	17.9	5.6	11.9
December 31, 2009	315.8	64.7	36.4	15.0	20.9

* Includes a $4.8 million adjustment that increased net income in the fourth quarter of 2009 related to prior periods. (See Note 9 for description of adjustment).

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) Before Income Taxes	Income Taxes (Benefit)	Earnings Available To FirstEnergy
			(In millions)		
TE					
March 31, 2010	$ 132.5	$ 20.9	$ 12.9	$ 5.4	$ 7.5
March 31, 2009	244.8	2.2	0.9	(0.1)	1.0
June 30, 2010	120.8	14.4	8.2	0.9	7.2
June 30, 2009	226.2	10.1	9.8	3.4	6.4
September 30, 2010	144.0	27.9	20.0	6.9	13.1
September 30, 2009	213.5	10.2	7.0	(0.1)	7.1
December 31, 2010	119.4	18.5	9.6	4.4	5.2
December 31, 2009**	149.4	23.8	14.2	4.7	9.5
Met-Ed					
March 31, 2010	$ 473.1	$ 34.8	$ 24.6	$ 12.3	$ 12.3
March 31, 2009	429.7	37.7	28.4	11.7	16.6
June 30, 2010	442.7	36.3	25.7	8.6	17.1
June 30, 2009	377.6	27.8	17.0	7.0	10.0
September 30, 2010	483.9	35.1	24.3	10.1	14.2
September 30, 2009	445.5	24.2	13.1	2.3	10.7
December 31, 2010	418.8	37.9	26.3	11.9	14.4
December 31, 2009	436.2	37.2	25.6	7.6	18.2
Penelec					
March 31, 2010	$ 403.5	$ 50.0	$ 34.5	$ 17.2	$ 17.3
March 31, 2009	388.6	44.2	31.8	13.1	18.7
June 30, 2010	366.5	34.9	18.8	5.8	13.0
June 30, 2009	331.7	36.0	25.1	10.2	14.8
September 30, 2010	389.9	41.0	25.1	5.3	19.8
September 30, 2009	355.5	32.3	21.8	6.0	15.8
December 31, 2010	380.0	38.0	22.3	12.9	9.4
December 31, 2009	373.1	49.4	32.4	16.4	16.1
JCP&L					
March 31, 2010	$ 703.7	$ 80.2	$ 52.8	$ 23.5	$ 29.2
March 31, 2009	773.7	77.1	50.1	22.6	27.6
June 30, 2010	720.6	111.7	83.4	33.5	49.9
June 30, 2009	708.1	95.4	67.9	29.8	38.1
September 30, 2010	968.5	175.7	147.3	64.4	82.9
September 30, 2009	868.2	133.7	105.6	43.4	62.2
December 31, 2010	634.3	85.9	56.9	26.9	30.1
December 31, 2009	642.7	84.1	55.7	13.0	42.6

** Includes a $2.5 million adjustment that increased net income in the fourth quarter of 2009 related to prior periods. (See Note 9 for description of adjustment).

22. 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 would 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.

In connection with the proposed merger, FirstEnergy recorded approximately $65 million ($47 million after tax) of merger transaction costs in the year ended December 31, 2010. These costs are expensed as incurred.

FIRSTENERGY CORP.

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS
(Unaudited)

For the Years Ended December 31,	2010	2009	2008	2007	2006	2005	2000
GENERAL FINANCIAL INFORMATION							
(Dollars in millions)							
Revenues	$ 13,339	$ 12,973	$ 13,627	$ 12,802	$ 11,501	$ 11,358	$ 6,308
Earnings Available to FirstEnergy Corp.	$ 784	$ 1,006	$ 1,342	$ 1,309	$ 1,254	$ 861	$ 599
SEC Ratio of Earnings to Fixed Charges	2.25	2.08	3.27	3.21	3.14	2.74	2.10
Capital Expenditures	$ 1,813	$ 1,770	$ 2,150	$ 1,496	$ 1,170	$ 1,144	$ 569
Total Capitalization	$ 21,092	$ 20,565	$ 17,415	$ 17,876	$ 17,604	$ 17,564	$ 11,205
Capitalization Ratios:							
Total Equity	40.4 %	41.6 %	47.7 %	50.4 %	51.5 %	53.5 %	47.3 %
Preferred and Preference Stock Subject to Mandatory Redemption	-	-	-	-	-	-	1.4
Long-Term Debt	59.6	58.4	52.3	49.6	48.5	46.5	51.3
Total Capitalization	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
Average Capital Costs:							
Preferred and Preference Stock			-	-	-	5.67%	7.92%
Long-Term Debt	5.87%	5.91%	5.95%	5.89%	6.33%	6.05%	7.84%
COMMON STOCK DATA							
Earnings per Share (a):							
Basic	$ 2.58	$ 3.31	$ 4.41	$ 4.27	$ 3.85	$ 2.68	$ 2.69
Diluted	$ 2.57	$ 3.29	$ 4.38	$ 4.22	$ 3.82	$ 2.67	$ 2.69
Return on Average Common Equity (a)	9.0%	11.7%	14.7%	14.9%	13.5%	10.0%	13.0%
Dividends Paid per Share	$ 2.20	$ 2.20	$ 2.20	$ 2.00	$ 1.80	$ 1.67	$ 1.50
Dividend Payout Ratio (a)	85%	66%	50%	47%	47%	62%	56%
Dividend Yield	5.9%	4.7%	4.5%	2.8%	3.0%	3.4%	4.8%
Price/Earnings Ratio (a)	14.3	14.0	11.0	17.0	15.7	18.3	11.7
Book Value per Common Share	$ 28.03	$ 28.08	$ 27.17	$ 29.45	$ 28.35	$ 27.98	$ 21.29
Market Price per Share	$ 37.02	$ 46.45	$ 48.58	$ 72.34	$ 60.30	$ 48.99	$ 31.56
Ratio of Market Price to Common Share Book Value	132%	165%	179%	246%	213%	175%	148%
OPERATING STATISTICS (b)							
Generation Kilowatt-Hour Sales (Millions):							
Residential	39,186	36,524	38,845	39,158	37,618	34,716	32,519
Commercial	36,151	32,056	34,405	36,879	35,390	32,878	33,139
Industrial	28,741	28,234	32,345	33,476	34,309	32,907	31,140
Other	504	519	538	540	542	547	522
Total Retail	104,582	97,333	106,133	110,053	107,859	101,048	97,320
Total Wholesale	19,625	21,126	24,654	24,114	23,083	28,521	13,761
Total Sales	124,207	118,459	130,787	134,167	130,942	129,569	111,081
Distribution Kilowatt-Hour Deliveries (Millions):							
Residential	39,772	37,574	38,869	39,207	37,587	39,106	33,089
Commercial	35,292	34,319	35,907	36,242	34,943	35,426	33,171
Industrial	32,415	29,900	35,044	36,460	36,537	37,060	37,963
Other	518	520	540	542	542	553	527
Total	107,997	102,313	110,360	112,451	109,609	112,145	104,750
Distribution Customers Served:							
Residential	3,964,690	3,964,341	3,963,229	3,956,837	3,959,043	3,941,030	3,798,716
Commercial	518,078	517,574	518,982	517,251	514,056	509,933	472,410
Industrial	9,975	10,128	10,225	10,367	10,458	10,637	18,996
Other	6,750	6,283	6,196	6,054	6,356	6,124	6,001
Total	4,499,493	4,498,326	4,498,632	4,490,509	4,489,913	4,467,724	4,296,123
Number of Employees	13,330	13,379	14,698	14,534	13,739	14,586	18,912

(a) Before discontinued operations in 2006 and 2005, and accounting changes in 2005.
(b) Reflects pro forma combined FirstEnergy and GPU statistics in 2000.

Shareholder Services

Transfer Agent and Registrar

American Stock Transfer & Trust Company, LLC, (AST) acts as the Transfer Agent, Dividend Paying Agent, and Shareholder Records Agent. Shareholders wanting to transfer stock, or who need assistance or information, can send their stock or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P.O. Box 2016, New York, NY 10272-2016. Shareholders also can call toll-free at 1-800-736-3402, between 8:00 a.m. and 7:00 p.m., Monday through Thursday; or between 8:00 a.m. and 5:00 p.m. on Friday, Eastern time. For Internet access to general shareholder and account information, visit the AST website at www.amstock.com/company/firstenergy.asp.

Stock Listing and Trading

Newspapers generally report FirstEnergy common stock under the abbreviation FSTENGY, but this can vary depending upon the newspaper. The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

Stock Investment Plan

Shareholders and others can purchase or sell shares of FirstEnergy common stock through the Company's Stock Investment Plan. Investors who are not registered shareholders can enroll with an initial $250 investment. Participants can invest all or some of their dividends or make optional payments at any time of at least $25 per payment up to $100,000 annually. Contact AST toll-free at 1-800-736-3402 to receive an enrollment form.

Safekeeping of Shares

Shareholders can request that AST hold their shares of FirstEnergy common stock in safekeeping. To take advantage of this service, shareholders should forward their common stock certificates to AST along with a signed letter requesting that AST hold the shares. Shareholders also should state whether future dividends for the held shares are to be reinvested or paid in cash. The certificates should not be endorsed, and registered mail is suggested. The shares will be held in uncertificated form, and AST will make certificates available to shareholders upon request. Shares held in safekeeping will be reported on dividend check stubs or Stock Investment Plan statements.

Direct Dividend Deposit

Shareholders can have their dividend payments automatically deposited to checking and savings accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST toll-free at 1-800-736-3402 to receive an authorization form.

Form 10-K Annual Report

Form 10-K, the Annual Report to the Securities and Exchange Commission, will be sent to you without charge upon written request to Rhonda S. Ferguson, Vice President and Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You can also view the Form 10-K by visiting the Company's website at www.firstenergycorp.com/financialreports.

Institutional Investor and Security Analyst Inquiries

Institutional investors and security analysts should direct inquiries to: Ronald E. Seeholzer, Vice President, Investor Relations, 330-384-5415.

Annual Meeting of Shareholders

Shareholders are invited to attend the 2011 Annual Meeting of Shareholders on Tuesday, May 17, at 10:30 a.m. Eastern time, at the John S. Knight Center, 77 East Mill Street, Akron, Ohio. Registered shareholders not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 28, 2011.

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