JERSEY CENTRAL POWER & LIGHT CO
Form 424B3
November 13, 2007
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Filed Pursuant to Rule 424(b)(3)
Registration No. 333-146968

PROSPECTUS

Offer To Exchange

$250,000,000 5.65% Exchange Senior Notes due 2017 that have been registered under the Securities Act of 1933 for all outstanding unregistered 5.65% Senior Notes due 2017

$300,000,000 6.15% Exchange Senior Notes due 2037 that have been registered under the Securities Act of 1933 for all outstanding unregistered 6.15% Senior Notes due 2037

We are offering to exchange up to $250,000,000 in aggregate principal amount of our registered 5.65% Exchange Senior Notes due 2017, or the 2017 Exchange Notes, and up to $300,000,000 in aggregate principal amount of our registered 6.15% Exchange Senior Notes due 2037, or the 2037 Exchange Notes, and together with the 2017 Exchange Notes, the Exchange Notes, for a like principal amount of unregistered $250,000,000 of our 5.65% Senior Notes due 2017, or the 2017 Notes, and unregistered $300,000,000 of our 6.15% Senior Notes due 2037, or the 2037 Notes, and together with the 2017 Notes, the Original Notes. The terms of the Exchange Notes are identical in all material respects to the terms of the Original Notes, except that the Exchange Notes have been registered under the Securities Act, and, therefore the terms relating to transfer restrictions, registration rights and additional interest applicable to the Original Notes are not applicable to the Exchange Notes, and the Exchange Notes will bear different CUSIP numbers.

This exchange offer will expire at 5:00 p.m., New York City time, on December 13, 2007, unless extended.

All Original Notes that are validly tendered, and not validly withdrawn, will be exchanged. You should carefully review the procedures for tendering the Original Notes beginning on page 94 of this prospectus.

Like the Original Notes, the Exchange Notes will be our senior unsecured obligations and will rank equally with all of our other unsecured and unsubordinated indebtedness, including other series of our currently outstanding senior notes.

You may validly withdraw tenders of the Original Notes at any time before the expiration of this exchange offer.

If you fail to tender your Original Notes, you will continue to hold unregistered, restricted securities, and your ability to transfer them could be adversely affected.

The exchange of the Original Notes for the Exchange Notes will not be a taxable event for United States federal income tax purposes.

The Original Notes may be exchanged for Exchange Notes only in denominations of $2,000 and integral multiples of $1,000 in excess thereof.

We will not receive any proceeds from this exchange offer.

No public market currently exists for the Exchange Notes. We do not intend to apply for listing of the Exchange Notes on any national securities exchange or to arrange for the Exchange Notes to be quoted on any automated quotation system, and therefore, an active public market is not anticipated.

Each holder of the Original Notes wishing to accept this exchange offer must effect a tender of the Original Notes by book-entry transfer into the exchange agent s account at The Depository Trust Company, or DTC. All deliveries are at the risk of the holder. You can find detailed instructions concerning delivery in the section of this prospectus entitled The Exchange Offer beginning on page 91.

See Risk Factors beginning on page 8 for a discussion of factors that you should consider in connection with an investment in the Exchange Notes.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

YOU SHOULD READ THIS ENTIRE DOCUMENT AND THE ACCOMPANYING LETTER OF TRANSMITTAL AND RELATED DOCUMENTS AND ANY AMENDMENTS OR SUPPLEMENTS CAREFULLY BEFORE MAKING YOUR DECISION TO PARTICIPATE IN THIS EXCHANGE OFFER.

The date of this prospectus is November 13, 2007.

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, or the SEC. You should rely only on the information we have provided in this prospectus. We have not authorized anyone to provide you with additional or different information. We are not making an offer of these securities in any jurisdiction where the offer is not permitted. You should assume that the information in this prospectus is accurate only as of the date on the front cover.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Some of the statements contained in this prospectus are forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. These statements include declarations regarding our or our management s intents, beliefs and current expectations. In some cases, you can identify forward-looking statements by terminology such as may, will, should, expects, plans, anticipates, believes, estimates, predicts, potential or continue or the negative of such ter comparable terminology. Forward-looking statements are not guarantees of future performance, and actual results could differ materially from those indicated by the forward-looking statements. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause our or our industry s actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by such forward-looking statements.

The forward-looking statements contained herein are qualified in their entirety by reference to the following important factors, which are difficult to predict, contain uncertainties, are beyond our control and may cause actual results to differ materially from those contained in forward-looking statements:

the speed and nature of increased competition and deregulation in the electric utility industry;

economic or weather conditions affecting future sales and margins;

changes in markets for energy services;

changing energy and commodity market prices;

our ability to continue to collect transition and other charges or to recover increased transmission costs;

maintenance costs being higher than anticipated;

the legal and regulatory uncertainty resulting from the implementation of the Energy Policy Act of 2005, or EPACT, including, but not limited to, the repeal of the Public Utility Holding Company Act of 1935, or PUHCA;

legislative and regulatory changes including revised environmental requirements;

adverse regulatory or legal decisions and the outcomes of governmental investigations and oversight (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies);

our inability to accomplish or realize anticipated benefits of strategic goals (including employee workforce initiatives);

the ability to comply with applicable state and federal reliability standards;

the ability to experience growth in our distribution business;

our ability to access the public securities and other capital markets and the cost of such capital;

the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003 regional power outages;

the risks and other factors discussed under Risk Factors, Business, Legal Proceedings, Selected Financial Information, Management Discussion And Analysis Of Financial Condition And Results Of Operations and in our consolidated financial statements and related notes included in this prospectus; and

other similar factors.

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Any forward-looking statements speak only as of the date of this prospectus, and we undertake no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of such factors, nor can we assess the impact of any such factor on our 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 foregoing review of factors should not be construed as exhaustive.

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WHERE YOU CAN FIND MORE INFORMATION

We voluntarily file annual, quarterly and current reports and other information with the SEC, although we are not currently subject to the informational requirements of the Exchange Act. As a result of the offering of the Exchange Notes, we will become subject to the informational requirements of the Exchange Act and, in accordance therewith, will file reports and other information with the SEC. These reports and other information can be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also read and copy these SEC filings by visiting the SEC s website at http://www.sec.gov or FirstEnergy s website at http://www.firstenergycorp.com. Information contained on FirstEnergy s website does not constitute part of this prospectus.

This prospectus is a part of a registration statement on Form S-4 under the Securities Act that we have filed with the SEC with respect to the Exchange Notes offered by this prospectus. This prospectus does not contain all of the information included in the registration statement. For further information, you should refer to the registration statement.

You may request additional copies of our reports or copies of our other SEC filings at no cost by writing or telephoning us at the following address:

Jersey Central Power & Light Company

c/o FirstEnergy Corp.

76 South Main Street

Akron, Ohio 44308-1890

Attention: Investor Services

(800) 736-3402

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SUMMARY

This summary highlights selected information from this prospectus. This summary is not complete and may not contain all of the information that you should consider prior to making a decision to exchange the Original Notes for Exchange Notes. You should read the entire prospectus carefully, including the Risk Factors section beginning on page 8 of this prospectus and the financial statements and notes to these statements set forth in this prospectus. Unless the context indicates otherwise, the words Jersey Central, the company, we, our, ours and us when used in this prospectus refer to Jersey Central Power & Light Company.

Jersey Central Power & Light Company

We are one of eight wholly-owned electric utility operating subsidiaries of FirstEnergy Corp., or FirstEnergy. We were organized under the laws of the State of New Jersey in 1925 and own property and do business as an electric public utility in that state. We engage in the transmission, distribution and sale of electric energy in an area of approximately 3,200 square miles in northern, western and east central New Jersey. We also engage in the sale, purchase and interchange of electric energy with other electric companies. The area we serve has a population of approximately 2.6 million.

Our principal executive offices are located at 76 South Main Street, Akron, Ohio 44308-1890. Our telephone number is (800) 736-3402.

Summary of the Exchange Offer

Issuance of the Original Notes	We issued and sold $250,000,000 aggregate principal amount of 5.65% Senior Notes due 2017 and $300,000,000 aggregate principal amount of 6.15% Senior Notes due 2037 on May 21, 2007 in a transaction not requiring registration under the Securities Act.
	The initial purchasers of the Original Notes sold beneficial interests in the Original Notes to qualified institutional buyers pursuant to Rule 144A of the Securities Act and to non-US persons pursuant to Regulation S of the Securities Act. All of the Original Notes originally issued by us on May 21, 2007 are currently outstanding.
The Exchange Offer; Exchange Notes	We are offering to exchange the Exchange Notes for the Original Notes to satisfy our obligations under the registration rights agreement we entered into when the Original Notes were issued and sold. The Exchange Notes will have been registered under the Securities Act and are of a like principal amount and like tenor of the Original Notes. Noteholders that validly tender their Original Notes and do not validly withdraw such tender before the expiration date will have the benefit of this exchange offer. The Original Notes may be exchanged for Exchange Notes only in denominations of $2,000 and integral multiples of $1,000 in excess thereof. In order to exchange your Original Notes, you must validly tender them before the expiration date of this exchange offer.
Expiration Date	5:00 p.m., New York City time, on December 13, 2007, unless extended by us in our sole discretion. If extended, the term expiration date as used in this prospectus will mean the latest date

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	and time to which this exchange offer is extended. We will accept for exchange any and all Original Notes which are validly tendered and not validly withdrawn before 5:00 p.m., New York City time, on the expiration date.
Conditions to the Exchange Offer	This exchange offer is subject to certain customary conditions, some of which we may waive. See The Exchange Offer Conditions to the Exchange Offer.
Consequences of Failure to Exchange Your Original Notes	If you fail to validly tender your Original Notes for Exchange Notes in accordance with the terms of this exchange offer, or withdraw your tender, your Original Notes will continue to be subject to transfer restrictions. If you are eligible to participate in this exchange offer and you fail to validly tender your Original Notes, or withdraw your tender, you will not have any further rights under the registration rights agreement, including the right to require us to register your Original Notes, but your Original Notes will remain outstanding and continue to accrue interest. See The Exchange Offer Consequences of Failure to Exchange.
	Because we anticipate that most holders of the Original Notes will elect to exchange their Original Notes, we expect that the liquidity of the market, if any, for any Original Notes remaining after the completion of this exchange offer will be substantially limited.
Procedures for Tendering Original Notes	If you are a holder of Original Notes who wishes to accept this exchange offer you must:
	complete, sign and date the accompanying letter of transmittal in accordance with the instructions contained in the letter of transmittal; and
	mail or otherwise deliver the letter of transmittal together with the Original Notes and any other required documentation to the exchange agent at the address set forth in this prospectus.
	However, if you hold your Original Notes through DTC, and wish to accept this exchange offer, you must arrange for DTC to transmit the required information to the exchange agent in connection with a book-entry transfer. See The Exchange Offer Procedures For Tendering Original Notes.
	By tendering your Original Notes in either of these manners, you will be making a number of important representations to us, as described under The Exchange Offer Resale of Exchange Notes, including that you do not intend to participate in a distribution of the Exchange Notes.
	Please do not send your letter of transmittal or certificates representing your Original Notes to us. Those documents should be sent only to the exchange agent. Questions regarding how to tender

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	the Original Notes and requests for information should be directed to the exchange agent. See The Exchange Offer Exchange Agent.
Guaranteed Delivery Procedures	If you wish to tender your Original Notes and your Original Notes are not immediately available or you cannot deliver your Original Notes, the letter of transmittal or any other documents required by the letter of transmittal to be delivered to the exchange agent, or you are unable to comply with the procedures for book-entry transfer prior to the expiration of this exchange offer, you must tender your Original Notes according to the guaranteed delivery procedures set forth in The Exchange Offer Procedures For Tendering Original Notes Guaranteed Delivery in order to participate in this exchange offer.
Special Procedures for Beneficial Owners	If your Original Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your Original Notes, we urge you to contact that person promptly and instruct the registered holder to tender your Original Notes on your behalf.
	If your Original Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your Original Notes on your own behalf, you must, prior to completing and executing the letter of transmittal and delivering your Original Notes to the exchange agent, either make appropriate arrangements to register ownership of the Original Notes in your name or obtain a properly completed note power from the registered holder. Please note that the transfer of registered ownership may take considerable time.
Withdrawal Rights	You may validly withdraw the tender of your Original Notes at any time prior to 5:00 p.m., New York City time, on the expiration date. See The Exchange Offer Withdrawal Rights.
Acceptance of the Original Notes and Delivery of Exchange Notes	We will accept for exchange any and all Original Notes which are validly tendered and not withdrawn in accordance with the terms and conditions of this exchange offer prior to 5:00 p.m., New York City time, on the expiration date. The Exchange Notes issued pursuant to this exchange offer will be delivered on the earliest practicable date following the exchange date. See The Exchange Offer Terms of the Exchange Offer.
Resales of Exchange Notes	We believe that you will be able to offer for resale, resell or otherwise transfer Exchange Notes issued in this exchange offer without compliance with the registration and prospectus delivery provisions of the Securities Act, provided that:
	you are acquiring the Exchange Notes in the ordinary course of your business;

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you have no arrangement or understanding with any person to participate in a distribution of the Exchange Notes;

you are not an affiliate of ours; and

if you are not a broker-dealer, you are not engaged in, and do not intend to engage in, the distribution of Exchange Notes.

In addition, each participating broker-dealer that receives Exchange Notes for its own account in exchange for the Original Notes which were acquired by the broker-dealer as a result of market-making or other trading activities must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of the Exchange Notes. A broker-dealer may use this prospectus for an offer to sell, resell or otherwise transfer Exchange Notes. See Plan of Distribution.

Our belief is based on interpretations by the staff of the SEC set forth in several no-action letters issued to third parties. The SEC has not considered this exchange offer in the context of a no-action letter, and we cannot be sure that the staff of the SEC would make a similar determination with respect to this exchange offer. See The Exchange Offer Resale of Exchange Notes.

If our belief is not accurate and you transfer an Exchange Note without delivering a prospectus meeting the requirements of the Securities Act or without an exemption from those requirements, you may incur liability under the Securities Act. We do not and will not assume, or indemnify you against, such liability.

Accrued Interest on the Exchange Notes and the Original Notes

Interest on each Exchange Note will accrue from the last date on which interest was paid on each Original Note surrendered in this exchange offer, or if no interest has been paid, from the original date of issuance of the Original Notes.

Material U.S. Federal Income Tax Consequences

The exchange of Original Notes for Exchange Notes pursuant to this exchange offer will not be a taxable event for United States federal income tax purposes. See Material U.S. Federal Income Tax Consequences.

Use of Proceeds

We will not receive any cash proceeds from the issuance of the Exchange Notes. See Use of Proceeds.

Exchange Agent

The Bank of New York Trust Company, N.A. is serving as the exchange agent in connection with the exchange offer. The address and telephone number of the exchange agent are listed below under The Exchange Offer Exchange Agent.

Registration Rights Agreement

The registration rights agreement by and between us and the initial purchasers of the Original Notes obligates us to provide you the opportunity to exchange your Original Notes for Exchange Notes

with substantially identical terms. This exchange offer satisfies that obligation. After this exchange offer is completed, you will no longer be entitled to any exchange or registration rights with respect to your Original Notes. However, under the circumstances described in the registration rights agreement, you may require us to file a shelf registration statement under the Securities Act. See The Exchange Offer Purpose of the Exchange Offer and The Exchange Offer Consequences of Failure to Exchange.

Summary of the Exchange Notes

Securities Offered	We are offering $550,000,000 aggregate principal amount of Exchange Notes of the following series: $250,000,000 aggregate principal amount of 5.65% Exchange Senior Notes due 2017; and $300,000,000 aggregate principal amount of 6.15% Exchange Senior Notes due 2037.
General	The form and terms of the Exchange Notes are identical in all material respects to the form and terms of the corresponding Original Notes, except that the Exchange Notes (i) will be registered under the Securities Act and, therefore, will not be subject to the restrictions on transfer applicable to the Original Notes, (ii) will bear different CUSIP numbers and (iii) will not be entitled to the rights of holders of the Original Notes under the registration rights agreement we entered into when the Original Notes were issued and sold. The Exchange Notes will evidence the same debt as the Original Notes and will be entitled to the benefits of the senior note indenture. See Description of the Exchange Notes.
Maturity	The 2017 Exchange Notes will mature on June 1, 2017, and the 2037 Exchange Notes will mature on June 1, 2037.
Interest	Interest on the 2017 Exchange Notes will accrue at a rate of 5.65% per annum, and interest on the 2037 Exchange Notes will accrue at a rate of 6.15% per annum. Interest on the Exchange Notes will accrue from the last date on which interest was paid on the Original Notes surrendered in the exchange offer, or, if no interest has been paid, from the original date of issuance of the Original Notes, and will be payable semi-annually in arrears on each June 1 and December 1, beginning on December 1, 2007, and at the respective maturity.
Listing	The Exchange Notes will not be listed on any stock exchange or quotation system. The Exchange Notes are a new issue for which there is currently no public market, and no assurance can be given as to the liquidity of or trading market for the Exchange Notes.
Senior Note Indenture	We will issue the Exchange Notes under the indenture, dated as of July 1, 1999, as supplemented, between us and The Bank of New York Trust Company, N.A., as successor senior note trustee, or the senior note indenture.

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Optional Redemption	Each series of the Exchange Notes will be redeemable in whole or in part, at our option, at any time prior to maturity, at a make-whole redemption price as described under Description of the Exchange Notes Optional Redemption.
Security and Ranking	The Exchange Notes will be our senior unsecured obligations and will rank equally with all of our other unsecured and unsubordinated indebtedness, including other series of our currently outstanding senior notes. On May 14, 2007, upon the occurrence of certain events described in this prospectus under the heading Description of the Exchange Notes General and Description of the Exchange Notes Security and Release Date, the first mortgage bonds securing the other series of our senior notes were released making our outstanding senior notes our unsecured general obligations.
Limitation on Liens	Subject to certain exceptions, so long as any Exchange Notes are outstanding, we may not issue, assume, guarantee or permit to exist any debt secured by any lien upon any of our operating property, except for certain permitted secured debt, without effectively securing all outstanding senior notes, including the Exchange Notes, equally and ratably with that debt (but only so long as such debt is secured). See Description of the Exchange Notes Certain Covenants Limitation on Liens.
Limitation on Sale and Lease-Back Transactions	Subject to certain exceptions, so long as any Exchange Notes are outstanding, we may not enter into or permit to exist any sale and lease-back transaction with respect to any operating property (except for transactions involving leases for a term, including renewals, of not more than 48 months), if the purchasers commitment is obtained more than 18 months after the later of the completion of the acquisition, construction or development of that operating property or the placing in operation of that operating property or of that operating property as constructed or developed or substantially repaired, altered or improved. See Description of the Exchange Notes Certain Covenants Limitation on Sale and Lease-Back Transactions.
Additional Issuances	We may from time to time, without the consent of the holders of the Exchange Notes or our other debt securities, create and issue additional debt securities having the same terms and conditions as the Exchange Notes so that the additional issuance is consolidated and forms a single series with the previously outstanding Exchange Notes.
Form, Denomination and Registration of the Exchange Notes	The Exchange Notes will be issued in fully-registered form without coupons represented by one or more fully registered global certificates. Each global certificate will be deposited with, or on behalf of DTC and registered in the name of Cede & Co., its nominee. Beneficial interests in the Exchange Notes will be represented through accounts of financial institutions acting on behalf of the

	beneficial owners as direct and indirect participants in DTC, including Euroclear and Clearstream, Luxembourg. Investors may elect to hold interests in the Exchange Notes through DTC or through either Euroclear or Clearstream, Luxembourg, if they are participants in those systems, or indirectly through organizations that are participants in those systems.
Ratings	The Original Notes were assigned ratings of Baa2 by Moody s Investors Service, Inc., or Moody s, BBB by Standard & Poor s Ratings Service, a division of The McGraw Hill Companies, Inc., or S&P, and BBB+ by Fitch Ratings, Ltd., or Fitch. A rating reflects only the view of a rating agency, and it is not a recommendation to buy, sell or hold the Original Notes. A rating does not address market prices or suitability for a particular investor. There can be no assurance that such ratings will not be lowered, suspended or withdrawn by a rating agency at any time.
Risk Factors	You should carefully read and consider, in addition to matters set forth elsewhere in this prospectus, the information in the Risk Factors section beginning on page 8.
Regulatory Approvals	The New Jersey Board of Public Utilities, or NJBPU, approved the issuance of the Original Notes and the Exchange Notes in an Order, dated April 13, 2007. No additional federal or state regulatory requirements must be complied with or approval must be obtained in connection with the exchange offer.
Trustee and Paying Agent	The Bank of New York Trust Company, N.A.
Governing Law	The senior note indenture and the Original Notes are, and the Exchange Notes will be, governed by, and construed in accordance with, the laws of the State of New York.

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RISK FACTORS

You should consider the following risk factors, in addition to the other information presented in this prospectus, in evaluating us, our business and whether to participate in this exchange offer. Any of the following risks, as well as other risks and uncertainties, could harm the value of the Exchange Notes directly or our business and financial results and thus indirectly cause the value of the Exchange Notes to decline, which in turn could cause you to lose all or part of your investment. The risks below are not the only ones related to us or the Exchange Notes. Additional risks not currently known to us or that we currently deem immaterial also may impair our business and cause the value of the Exchange Notes to decline. See Cautionary Note Regarding Forward-Looking Statements.

Risks Related to the Exchange Offer

If you do not properly tender your Original Notes for Exchange Notes, you will continue to hold unregistered certificates that are subject to transfer restrictions.

We will only issue Exchange Notes in exchange for Original Notes that are received by the exchange agent in a timely manner together with all required documents. Therefore, you should allow sufficient time to ensure timely delivery of the Original Notes, and you should carefully follow the instructions on how to tender your Original Notes set forth under The Exchange Offer Procedures For Tendering Original Notes and in the letter of transmittal that you receive with this prospectus. Neither we nor the exchange agent are required to tell you of any defects or irregularities with respect to your tender of the Original Notes.

If you do not tender your Original Notes or if we do not accept your Original Notes because you did not tender your Original Notes properly, you will continue to hold Original Notes. Any Original Notes that remain outstanding after the expiration of this exchange offer will continue to be subject to restrictions on their transfer in accordance with the Securities Act. After the expiration of this exchange offer, holders of Original Notes will not (with limited exceptions) have any further rights to have their Original Notes registered under the Securities Act. In addition, if you tender your Original Notes for the purpose of participating in a distribution of the Exchange Notes, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the Exchange Notes. If you continue to hold any Original Notes after this exchange offer is completed, you may have difficulty selling them because of the restrictions on transfer and because there will be fewer Original Notes outstanding. The value of the remaining Original Notes could be adversely affected by the conclusion of this exchange offer. There may be no market for the remaining Original Notes, and thus you may be unable to sell such Original Notes.

If an active trading market does not develop for the Exchange Notes, you may be unable to sell the Exchange Notes or to sell them at a price you deem sufficient.

The Exchange Notes will be new securities for which there is no established trading market. We do not intend to apply for listing of the Exchange Notes on any national securities exchange or to arrange for the Exchange Notes to be quoted on any automated system. We provide no assurance as to:

- the liquidity of any trading market that may develop for the Exchange Notes;
- the ability of holders to sell their Exchange Notes; or
- the price at which holders would be able to sell their Exchange Notes.

Even if a trading market develops, the Exchange Notes may trade at higher or lower prices than their principal amount or purchase price, depending on many factors, including:

- prevailing interest rates;

the number of holders of the Exchange Notes;

the interest of securities dealers in making a market for the Exchange Notes; and

our operating results.

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If a market for the Exchange Notes does not develop, purchasers may be unable to resell the Exchange Notes for an extended period of time. Consequently, a holder of Exchange Notes may not be able to liquidate its investment readily, and the Exchange Notes may not be readily accepted as collateral for loans. In addition, market-making activities will be subject to restrictions of the Securities Act and the Exchange Act.

In addition, if a large number of holders of the Original Notes do not tender the Original Notes or tender the Original Notes improperly, the limited amount of the Exchange Notes that would be issued and outstanding after we complete this exchange offer could adversely affect the development of a market for the Exchange Notes.

If you are a broker-dealer, your ability to transfer the Original Notes may be restricted.

A broker-dealer that purchased Original Notes for its own account as part of market-making or trading activities must deliver a prospectus when it sells the Exchange Notes. Our obligation to make this prospectus available to broker-dealers is limited. Consequently, we cannot guarantee that a proper prospectus will be available to broker-dealers wishing to resell their Exchange Notes.

Risks Related to Our Business Operations and Industry

Because our actions in obtaining a supply of electricity are subject to regulatory prudence reviews, there exists the potential for the disallowance and, therefore, non-recovery of a portion of the costs of that supply.

We currently obtain our electricity to serve our basic generation service, or BGS, customers entirely from contracted purchases from third-party suppliers through an auction process authorized by the NJBPU. Auctions in February 2005, 2006 and 2007 resulted in supply contracts covering portions of our requirements for various periods through May 31, 2010. The prices charged to our non-shopping customers since August 1, 2003 have essentially equaled our costs. If any of these third-party suppliers were to default on their obligations, and no other third-party supplier steps in to supply that load, or if future auctions do not result in contracts for all of our supply requirements, we would purchase replacement power in the open market at prices that may exceed our charges to customers.

Although we are permitted to defer for future collection from customers the amounts by which our BGS costs and our costs incurred under non-utility generation, or NUG, agreements exceed amounts collected through our BGS and non-utility generation charge, or NUGC, rates, or deferred balance, our actions in purchasing any such power in the open market would be subject to subsequent regulatory prudence reviews, which could lead to the disallowance of some of those costs. As of September 30, 2007, our accumulated deferred cost balance totaled approximately $330 million.

Electricity currently purchased under existing agreements with non-utility generators and power we generate is sold primarily into the wholesale market, which purchases and sales are also subject to regulatory prudence reviews. Any of our costs that are disallowed for recovery would be charged against our earnings. We cannot predict the result of future regulatory prudence reviews, which could have an adverse impact on our results of operations.

We are subject to complex and changing government regulations that may require increased expense and/or changes in business strategy that could have a negative impact on our results of operations.

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influences our operating environment. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. However, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in or reinterpretations of existing laws or regulations or the imposition of new laws or regulations may require us to incur additional expenses or change the way we run our businesses, and therefore may have an adverse impact on our results of operations.

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Our retail rates, conditions of service, issuance of securities and other matters are subject to regulation by the NJBPU. With respect to our wholesale and interstate electric operations and rates, including regulation of our accounting policies and practices, we are subject to regulation by the Federal Energy Regulatory Commission, or FERC. Decisions by either of these regulatory bodies could affect us adversely for the reasons described above.

The EPACT affects various aspects of electric generation, transmission and distribution. One of the provisions of EPACT gives the FERC the authority to certify an electric reliability organization, or ERO, that will establish and enforce mandatory bulk power reliability standards, subject to FERC review and approval. The EPACT repealed the PUHCA effective February 8, 2006. Some of the PUHCA s consumer protection authority has been transferred to the FERC and state utility commissions. The repeal of the PUHCA and the impact of this legislation and its implementation on both a federal and state level could have a significant impact on our operations.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact us. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders. Another revised draft was circulated by the NJBPU Staff on February 8, 2007. We are not able to predict the outcome of this proceeding at this time.

New Jersey statutes require the state to periodically undertake a planning process known as the energy master plan, or EMP, to address energy-related issues. In October 2006, the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following: reduce the total projected electricity demand by 20% by 2020; meet 22.5% of New Jersey s electricity needs with renewable energy resources by 2020; reduce air pollution related to energy use; encourage and maintain economic growth and development; achieve a 20% reduction in both the customer average interruption duration index and the system average interruption frequency index by 2020; maintain unit prices for electricity at no more than 5% above the regional average price; and eliminate transmission congestion by 2020. Comments on the objectives and participation in the development of the EMP have been solicited. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in late 2007. A final draft of the EMP is expected to be presented to the Governor in late 2007 with further public hearings anticipated in early 2008. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the NJBPU Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments, which were due on September 26, 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on our operations.

Our facilities may not operate as planned, which may increase our expenses or decrease our revenues and, thus, have an adverse effect on our financial performance.

Operation of transmission and distribution facilities involves risk, including potential breakdown or failure of equipment or processes, accidents, labor disputes, stray voltage and performance below expected levels. In

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addition, weather-related incidents and other natural disasters can disrupt transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of those facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties. Any of these occurrences could result in reduced revenues or increased expenses, including higher maintenance costs that we may not be able to recover from customers. Moreover, if we are unable to perform our contractual obligations, penalties or damages may result.

As more fully discussed under Business Legal Proceedings, litigation relating to power outages in our service territory in 1999 is pending against us. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against us, our then parent, GPU, Inc., or GPU (which merged into FirstEnergy Corp. in 2001) and certain of our affiliates, seeking compensatory and punitive damages arising from the July 1999 service interruptions in our territory. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and decertified the class. The plaintiffs appealed this ruling to the New Jersey Appellate Division, which on March 7, 2007 remanded the matter back to the Trial Court to allow the plaintiffs sufficient time to establish a damage model or individual proof of damages. We filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court, which was denied on May 9, 2007. Proceedings are continuing in the Superior Court. We are defending this class action lawsuit, but are unable to predict the outcome of this matter. No liability has been accrued as of September 30, 2007.

Restructuring and deregulation in the electric utility industry may result in increased competition and unrecoverable costs that could adversely affect our business and results of operations.

As a result of the actions taken by state legislative bodies over the last few years, major changes in the electric utility business have occurred and are continuing to take place in parts of the United States, including New Jersey where we operate. The FERC and the U.S. Congress also propose changes from time to time in the structure and conduct of the utility industry. The FERC s ongoing efforts to promote regional transmission organizations, or RTOs, like the PJM Interconnection L.L.C., or PJM, which includes us as a transmission owner, for example, may affect how we operate and our costs of doing business. If these and other restructuring and deregulation-related efforts and proceedings result in unrecoverable costs, our business and results of operations may be adversely affected. We cannot predict the extent and timing of further efforts to restructure, deregulate or re-regulate us or our industry.

Weather conditions such as tornadoes, hurricanes, ice storms and droughts, as well as seasonal temperature variations could have a negative impact on our results of operations.

Weather conditions directly influence the demand for electric power. In our service areas, demand for power peaks during the summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. However, severe weather, such as tornadoes, hurricanes, ice or snow storms or droughts, or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable through our prices. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period.

Increases in interest rates and/or a downgrade of our credit ratings could negatively affect our financing costs and our ability to access capital.

We have exposure to future interest rates as we plan to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash flows from operations. A downgrade in our credit ratings from the nationally-recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets. A ratings downgrade would also increase the fees we pay on our various credit facilities, thus increasing the cost of our working capital. A ratings downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital. Our senior unsecured debt ratings from S&P and Moody s are investment grade. The current ratings outlook is negative from S&P and stable from Moody s.

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

Acts of war or terrorism could negatively impact our business.

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

We are subject to financial performance risks related to the economic cycles of the electric utility industry.

Our business follows the economic cycles of our customers. Sustained downturns or sluggishness in the economy generally affects the markets in which we operate and negatively influences energy operations. Declines in demand for electricity as a result of economic downturns will reduce overall electricity sales and lessen cash flows, especially as industrial customers reduce production, resulting in less consumption of electricity. Economic conditions also impact the rate of delinquent customer accounts receivable.

We face certain human resource risks associated with the availability of, and our ability to attract and retain, trained and qualified management and labor to meet future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility industry. The median age of utility workers is significantly higher than the national average. Today, nearly one-half of the industry s workforce is age 45 or older. Consequently, we face the difficult challenge of finding ways to retain our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Mitigating these risks could require additional financial commitments.

USE OF PROCEEDS

This exchange offer is intended to satisfy certain of our obligations under the related registration rights agreement.

We will not receive any cash proceeds from the issuance of the Exchange Notes in this exchange offer. In consideration for issuing the Exchange Notes as contemplated in this prospectus, we will receive outstanding Original Notes in like principal amount. We will cancel all Original Notes surrendered to us in this exchange offer.

We used the proceeds we received from the issuance of the Original Notes to refinance certain series of our outstanding first mortgage bonds, to fund a repurchase of $125 million of our common stock from our parent, FirstEnergy, and for general corporate purposes.

RATIO OF EARNINGS TO FIXED CHARGES

For the Years Ended December 31,					For the Nine Months Ended September 30,	
2002	**2003**	**2004**	**2005**	**2006**	**2006**	**2007**
					(unaudited)	
5.12	2.11	3.19	4.44	4.28	4.57	4.30

Earnings for purposes of the calculation of Ratio of Earnings to Fixed Charges have been computed by adding to Income before extraordinary items total interest and other charges, before reduction for amounts capitalized, provision for income taxes and the estimated interest element of rentals charged to income. Fixed charges include interest on long-term debt, other interest expense and the estimated interest element of rentals charged to income.

CAPITALIZATION

The following table sets forth our capitalization as of September 30, 2007. The table below should be read in conjunction with Selected Financial Information, Management s Discussion And Analysis Of Financial Condition And Results Of Operations and with our consolidated financial statements and related notes included in this prospectus.

	As of September 30, 2007 *(In thousands)*	
Common Stockholder s Equity	$ 3,020,943	65.8%
Long-Term Debt and Other Long-Term Obligations	1,568,296	34.2%
Total Capitalization	$ 4,589,239	100.0%

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SELECTED FINANCIAL INFORMATION

The following table contains: (1) our selected financial data for the five fiscal years ended December 31, 2006, and as of December 31 for each of those years, which have been derived from our audited consolidated financial statements (our audited financial statements for the three fiscal years ended December 31, 2006 are included in this prospectus) and (2) our selected financial data for the nine months ended September 30, 2006 and 2007 and as of September 30, 2007, which have been derived from our unaudited consolidated financial statements included in this prospectus. The selected financial data as of September 30, 2006 and 2007 and for the nine months ended September 30, 2006 and 2007 are unaudited. For the nine months ended September 30, 2006 and 2007, all adjustments, consisting only of normal and recurring adjustments, which are, in our opinion, necessary for a fair presentation of the interim consolidated financial statements, have been included. Results for the nine months ended September 30, 2007 are not necessarily indicative of the results for the full year. The exchange of the Original Notes for the Exchange Notes will not be a taxable event for United States federal income tax purposes. See Material U.S. Federal Income Tax Consequences.

The following selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, the section below entitled Management s Discussion And Analysis Of Financial Condition And Results Of Operations and our consolidated financial statements and the notes to our consolidated financial statements included in this prospectus.

	Year Ended December 31,					Nine Months Ended September 30,	
	2002	2003	2004	2005	2006	2006	2007
				(In thousands)		(unaudited)	
Operating Revenues	$ 2,328,415	$ 2,359,646	$ 2,206,987	$ 2,602,234	$ 2,667,645	$ 2,098,344	$ 2,496,995
Operating Income	332,953	144,606	273,334	388,377	403,668	325,186	343,345
Total Assets	8,062,148	7,583,361	7,296,532	7,584,106	7,482,565	7,699,268	7,249,041
Long-Term Obligations and Company-Obligated Mandatorily Redeemable Preferred Stock	1,335,690	1,095,991	1,238,984	972,061	1,320,341	1,327,809	1,568,296
Consolidated Ratio of Earnings to Fixed Charges(1)	5.12	2.11	3.19	4.44	4.28	4.57	4.30

(1) Earnings for purposes of the calculation of Ratio of Earnings to Fixed Charges have been computed by adding to Income before extraordinary items total interest and other charges, before reduction for amounts capitalized, provision for income taxes and the estimated interest element of rentals charged to income. Fixed charges include interest on long-term debt, other interest expense and the estimated interest element of rentals charged to income.

MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

We are one of eight wholly-owned electric operating subsidiaries of FirstEnergy, which include American Transmission Systems, Inc., or ATSI, Ohio Edison Company, or OE, The Cleveland Electric Illuminating Company, or CEI, The Toledo Edison Company, or TE, Pennsylvania Power Company, or Penn, Metropolitan Edison Company, or Met-Ed, and Pennsylvania Electric Company, or Penelec. FirstEnergy is a diversified energy company headquartered in Akron, Ohio. FirstEnergy s subsidiaries and affiliates are involved in the generation, transmission and/or distribution of electricity, as well as energy management and other energy-related services. FirstEnergy s eight electric utility operating companies comprise the nation s fifth largest investor-owned electric system, serving 4.5 million retail customers within a 36,100-square-mile area of Ohio, Pennsylvania and New Jersey.

We were organized under the laws of the State of New Jersey in 1925 and own property and do business as an electric public utility in that state. As one of FirstEnergy s operating subsidiaries, we provide transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. Our transmission system is overseen by PJM, a RTO. We also engage in the sale, purchase and interchange of electric energy with other electric companies. The area we serve has a population of approximately 2.6 million. We comply with the regulations, orders, policies and practices prescribed by the SEC, the FERC and the NJBPU.

Reclassifications

As discussed in Note 1 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications did not change previously reported earnings for 2005 and 2004. All reclassifications have been evaluated and determined to be properly reflected as reclassifications in the respective period as presented in the consolidated balance sheets and statements of cash flows.

Results of Operations

Nine Months Ended September 30, 2007

Earnings on common stock increased to $164 million in the first nine months of 2007 compared to $152 million for the same period in 2006. The increase was primarily due to higher revenues and lower operating costs, partially offset by higher purchased power costs and increased amortization of regulatory assets.

Years Ended December 31, 2006 and 2005

Earnings on common stock increased to $190 million in 2006 from $182 million in 2005, as increases in operating revenues and lower other operating costs were partially offset by increases in purchased power costs. Earnings on common stock in 2005 increased to $182 million from $107 million in 2004, due to higher operating revenues that were partially offset by increases in purchased power and other operating costs.

Revenues

Nine Months Ended September 30, 2007

Revenues increased $399 million or 19% in the first nine months of 2007 compared with the same period of 2006. Retail and wholesale generation revenues increased by $250 million and $49 million, respectively, in the first nine months of 2007.

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Retail generation revenues from all customer classes increased in the first nine months of 2007 compared to 2006 due to higher unit prices resulting from the BGS auctions effective June 1, 2006 and June 1, 2007 and higher retail generation kilowatt-hour, or KWH, sales. Sales volume increased as a result of weather conditions in the first nine months of 2007 (heating degree days were 15.8% greater than the first nine months of 2006 and cooling degree days decreased slightly). Industrial generation KWH sales declined in the first nine months of 2007 from the same period in 2006 due to an increase in customer shopping.

Wholesale generation revenues increased $49 million in the first nine months of 2007 due to higher market prices, partially offset by a 3.0% decrease in sales volume compared with the first nine months of 2006.

Changes in retail generation KWH sales and revenues by customer class in the first nine months of 2007 compared to the same period of 2006 are summarized in the following table:

Retail Generation KWH Sales	Increase (Decrease)
Residential	2.3%
Commercial	1.6%
Industrial	(7.0)%
Net Increase in Generation Sales	**1.6%**

Retail Generation Revenues	Increase
	(In millions)
Residential	$ 145
Commercial	100
Industrial	5
Increase in Generation Revenues	**$ 250**

Distribution revenues increased in the first nine months of 2007 compared to the same period of 2006 due to higher composite unit prices and increased KWH deliveries, reflecting the weather impacts described above. The higher unit prices resulted from a NUGC rate increase effective in December 2006.

Changes in distribution KWH deliveries and revenues in the first nine months of 2007 compared to the corresponding period of 2006 are summarized in the following tables.

Distribution KWH Deliveries	Increase
Residential	2.3%
Commercial	3.3%
Industrial	1.1%
Increase in Distribution Deliveries	**2.6%**

Distribution Revenues	Increase
	(In millions)
Residential	$ 35
Commercial	38
Industrial	6
Increase in Distribution Revenues	**$ 79**

The higher revenues for the first nine months of 2007 also included $20 million of increased revenues resulting from the August 2006 securitization of deferred costs associated with our BGS supply.

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Years Ended December 31, 2006 and 2005

Revenues increased $65 million or 2.5% in 2006 compared with 2005. The higher revenues reflected increases in retail generation revenues of $150 million and miscellaneous revenue of $6 million partially offset by declines in distribution throughput revenues of $25 million and wholesale revenues of $66 million. Retail generation sales revenues increased in 2006 from 2005 due to higher unit prices resulting from the BGS auction, partially offset by lower volumes. Retail generation KWH sales declines in the residential (5.5%) and industrial (3.6%) sectors were partially offset by an increase in sales to the commercial sector (1.0%). The decline in retail generation KWH sales was due to milder weather in 2006 compared to 2005 heating degree days decreased by 18.5% and cooling degree days decreased by 16.0%.

The $25 million decline in distribution revenues was due to a 3.5% volume decrease in 2006 from the previous year, partially offset by higher composite unit prices. The higher composite prices reflected the impact of the distribution rate increase effective June 1, 2005 due to the NJBPU stipulated settlements. See Note 7 to the consolidated financial statements. Lower residential sector deliveries and a slight change in commercial sector deliveries resulted from the milder temperatures in 2006; a decrease in industrial sector deliveries reflected slowing economic conditions in our service area.

Revenues from wholesale sales decreased by $66 million in 2006 as compared to 2005 due to lower unit prices and a 2.0% decline in KWH sales.

Revenues increased $395 million or 17.9% in 2005 compared with 2004. The higher revenues consisted of increases in retail generation revenues of $195 million, distribution throughput revenues of $123 million and wholesale revenues of $75 million. Retail generation sales revenues increased in 2005 from 2004 due to higher volumes and unit prices resulting from the BGS auction. Retail generation KWH sales increases in the residential (13.9%) and commercial (13.5%) sectors more than offset a decline in sales to the industrial sector (6.3%) due to changes in customer shopping. Generation provided by alternative suppliers to residential and commercial customers as a percent of total sales in our franchise area decreased by 5.2 and 5.1 percentage points, respectively, while the percentage of shopping by industrial customers increased by 1.6 percentage points.

The $123 million increase in distribution deliveries during 2005 was due to higher composite unit prices, coupled with a 6.2% volume increase in 2005 from the previous year. The higher composite prices reflected the impact of the distribution rate increase effective June 1, 2005 due to the NJBPU stipulated settlements. See Note 7 to the consolidated financial statements. Higher residential and commercial sector deliveries resulted, in large part, from warmer summer temperatures and colder winter temperatures in 2005 and a slight increase in industrial sector deliveries as a result of improving economic conditions.

Changes in electric generation sales and distribution deliveries in 2006 and 2005, compared to the prior year, are summarized in the following table:

Changes in KWH Sales	**2006**	**2005**
Increase (Decrease)		
Electric Generation:		
Retail	(2.8)%	12.8%
Wholesale	(2.0)%	(5.1)%
Total Electric Generation Sales	**(2.6)%**	**8.6%**
Distribution Deliveries:		
Residential	(5.5)%	8.0%
Commercial	0.2%	6.3%
Industrial	(7.9)%	0.1%
Total Distribution Deliveries	**(3.5)%**	**6.2%**

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Expenses

Nine Months Ended September 30, 2007

Total expenses increased by $380 million in the first nine months of 2007 as compared to the same period of 2006. The following table presents changes from the prior year by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ 300
Other operating costs	(9)
Provision for depreciation	1
Amortization of regulatory assets	87
General Taxes	1
Net increase in expenses	**$ 380**

The increase in purchased power costs primarily reflected higher unit prices resulting from the June 2006 and June 2007 BGS auctions. Other operating costs decreased $9 million in the first nine months of 2007 primarily due to lower employee benefit costs. Amortization of regulatory assets increased $87 million in the first nine months of 2007 due to higher cost recovery associated with the December 2006 NUGC rate increase.

Other expenses increased $9 million in the first nine months of 2007 from the same period in 2006 primarily due to interest expense associated with our $550 million issuance of the Original Notes in May 2007.

Years Ended December 31, 2006 and 2005

Total expenses increased $50 million in 2006 and $280 million in 2005, compared to the preceding year. The increase in 2006 was primarily due to higher purchased power costs and the absence of new regulatory asset deferrals, offset by reductions in other operating costs and amortization of regulatory assets. The increase in 2005 compared to 2004 was primarily due to higher purchased power costs. The following table presents changes in 2006 and 2005 from the prior year by expense category:

Operating Expenses Changes	2006	2005
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 91	$ 263
Other operating costs	(54)	25
Provision for depreciation	3	5
Amortization of regulatory assets	(18)	14
Deferral of new regulatory assets	29	(29)
General taxes	(1)	2
Net increase in expenses	$ 50	$ 280

Purchased power increased $91 million in 2006 compared to 2005. The increased purchased power costs have no impact on our earnings as all power is provided from the BGS auction and deferral accounting ensures the matching of revenue with purchased power expense. The increased purchased power costs reflected higher unit prices, partially offset by reduced KWH purchases due to lower generation sales requirements as discussed above. The decrease in other operating expenses of $54 million in 2006 reflected the absence of an accrual for a potential labor arbitration award and the impact of the labor union strike that ended in March 2005.

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New regulatory asset deferrals decreased $29 million in 2006, as the prior year reflected the NJBPU approval to defer previously incurred reliability expenses for recovery from customers. Amortization of regulatory assets decreased $18 million in 2006 as compared to 2005 due to a reduced level of market transition charge, or MTC, revenue recovery.

Purchased power costs increased $263 million in 2005 compared to 2004, reflecting higher KWH purchases due to increased generation sales requirements and higher unit prices. As discussed above, the increased purchased power costs have no impact on our earnings as deferral accounting ensures the matching of revenue with purchased power expense. Other operating expenses increased $25 million in 2005 compared to 2004, primarily due to our recording a $16 million liability for a potential labor arbitration award.

Deferral of new regulatory assets of $29 million in 2005 reflected the NJBPU approval to defer previously incurred reliability expenses for recovery from customers. Amortization of regulatory assets increased $14 million in 2005 as compared to 2004 due to an increase in the level of MTC revenue recovery.

Net Interest Charges

Net interest charges increased $2 million in 2006 and decreased $3 million in 2005, compared to the prior year. These changes reflected debt issuances of $382 million and redemptions of $207 million in 2006 and redemptions of $56 million in 2005.

Capital Resources and Liquidity

Our cash requirements in 2006 for operating expenses, construction expenditures and scheduled debt maturities were met with a combination of cash from operations and funds from the capital markets. During 2007 and thereafter, we expect to meet our contractual obligations primarily with cash from operations, short-term credit arrangements and funds from the capital markets. Borrowing capacity under our credit facilities is available to manage our working capital requirements.

Changes in Cash Position

As of December 31, 2006 and 2005, we had $41,000 and $102,000 of cash and cash equivalents, respectively. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities was $190 million in 2006, $507 million in 2005 and $263 million in 2004, summarized as follows:

	Years Ended December 31,		
Operating Cash Flows	**2006**	**2005**	**2004**
		(In millions)	
Net income	$ 191	$ 183	$ 108
Net non-cash charges	108	112	118
Pension trust contribution*	5	(54)	(37)
Cash collateral from (returned to) suppliers	(109)	135	7
Working capital and other	(5)	131	67
Net cash provided from operating activities	$ 190	$ 507	$ 263

* Pension trust contributions in 2005 and 2004 were each net of $25 million of income tax benefits. The $5 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to a January 2007 pension contribution.

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Net cash provided from operating activities decreased by $317 million in 2006 from 2005 as a result of $244 million of cash collateral returned to suppliers, $136 million decrease from working capital and other and a $4 million decrease in net non-cash charges, partially offset by an $8 million increase in net income (as described above under Results of Operations) and the tax benefit in 2006 relating to the January 2007 pension contribution. The decrease in working capital and other was attributable to changes to accrued taxes of $87 million and a decrease in cash of $27 million from the collection of receivables.

Net cash provided from operating activities increased $244 million in 2005 compared to 2004 due to a $75 million increase in net income as described above under Results of Operations, a $128 million increase in cash collateral collected from suppliers and a $64 million increase from working capital and other, which was partially offset by a $17 million increase in after-tax voluntary pension trust contributions in 2005 from 2004. The increase from working capital and other was attributable to a $41 million increase in cash from the collection of receivables and a $45 million increase in accounts payable.

Cash Flows From Financing Activities

Net cash used for financing activities was $10 million, $298 million and $82 million in 2006, 2005 and 2004, respectively, primarily reflecting the new issues and redemptions shown below:

Securities Issued or Redeemed in	2006	2005	2004
		(In millions)	
New Issues:			
Secured notes	$ 382	$	$ 300
Redemptions:			
FMB	$ 40	$ 56	$ 290
Secured notes	150		
Common stock	77		
Preferred stock	13		
Transition bonds	17	17	16
Other			3
Total redemptions	$ 297	$ 73	$ 309
Short-term borrowings, net	$ 5	$ (67)	$ 18

Net cash used for financing activities decreased $288 million in 2006 from 2005. The decrease resulted primarily from the issuance of $382 million in long-term debt. Net cash used for financing activities increased $216 million in 2005 from 2004 as a result of a $68 million increase in common stock dividends to FirstEnergy and to new financing.

We had approximately $24 million of cash and temporary investments (which includes short-term notes receivable from associated companies) and approximately $187 million of short-term indebtedness as of December 31, 2006. We have authorization from the FERC to incur short-term debt of up to our charter limit of $429 million (including the utility money pool). As our mortgage indenture was terminated as of September 14, 2007, we may no longer issue FMB. In addition, our senior note indenture prohibits us (subject to certain exceptions) from issuing any debt which is senior to the senior notes. As a result of our redeeming all remaining outstanding preferred stock on September 15, 2006, our applicable earnings coverage test is inoperative. In the event that we would issue preferred stock in the future, the applicable earnings coverage test will govern the amount of additional preferred stock that we may issue.

On June 8, 2006, the NJBPU approved our request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, one of our wholly-owned subsidiaries, issued $182 million of transition bonds with a weighted average interest rate of 5.5%. As required by the Electric Discount and Energy Competition Act of 1999, as amended, we used the proceeds principally to reduce stranded costs, including basic generation transition costs, through the retirement of debt, including short-term debt, or equity or both, and also to pay related expenses.

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On May 12, 2006, we issued $200 million of 6.40% secured Senior Notes due 2036. The proceeds of the offering were used to repay at maturity $150 million aggregate principal amount of our 6.45% Senior Notes due May 15, 2006 and for general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities decreased $29 million in 2006 and increased $28 million in 2005. The decrease in 2006 resulted from a reduction of $49 million in property additions offset by loans to associated companies and an increase in the amount of restricted funds. The increase in 2005 resulted primarily from a $30 million increase in property additions.

Contractual Obligations

As of December 31, 2006, our estimated cash payments under existing contractual obligations that we considered firm obligations were as follows:

Contractual Obligations	Total	2007	2008-2009	2010-2011	Thereafter
			(In millions)		
Long-term debt(1)	$ 1,366	$ 33	$ 56	$ 63	$ 1,214
Short-term borrowings	187	187			
Interest on long-term debt	1,144	81	157	151	755
Operating leases(2)	102	8	17	15	62
Pension funding(3)	18	18			
Purchases(4)	2,692	574	1,010	732	376
Total	$ 5,509	$ 901	$ 1,240	$ 961	$ 2,407

(1) Amounts reflected do not include interest on long-term debt.

(2) Operating lease payments are net of reimbursements from subleasees. See Note 5 to the consolidated financial statements.

(3) We estimate that no further pension contributions will be required during the 2008-2011 period to maintain our defined benefit pension plan s funding at a minimum required level as determined by government regulations. We are unable to estimate projected contributions beyond 2011. See Note 3 to the consolidated financial statements.

(4) Power purchases under contracts with fixed or minimum quantities and approximate timing.

Market Risk Information

We use 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 FirstEnergy senior management, provides general oversight to risk management activities. Commodity derivative contracts were valued at $1.2 billion as of December 31, 2006.

Commodity Price Risk

We are exposed to market risk primarily due to fluctuations in electricity, energy transmission and natural gas prices. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. Derivatives that fall within the scope of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, or SFAS 133, must be recorded at their fair value and marked to market. The majority of our derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the table below. Contracts that are not exempt from such treatment include power purchase agreements with NUG entities that were structured pursuant to the Public

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Utility Regulatory Act of 1978. These non-trading contracts are adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2006 is summarized in the following table:

Decrease in the Fair Value of Derivative Contracts	Non-Hedge	Hedge *(In millions)*	Total
Change in the fair value of commodity derivative contracts:			
Outstanding net liabilities as of January 1, 2006	$ (1,223)	$	$ (1,223)
New contract value when entered			
Additions/Changes in value of existing contracts	(239)		(239)
Change in techniques/assumptions			
Settled contracts	291		291
Net Liabilities Derivatives Contracts as of December 31, 2006(1)	$ (1,171)	$	$ (1,171)
Impact of Changes in Commodity Derivative Contracts(2)			
Income Statement Effects (Pre-Tax)	$ (1)	$	$ (1)
Balance Sheet Effects:			
OCI (Pre-Tax)	$	$	$
Regulatory Asset (Net)	$ (53)	$	$ (53)

(1) Includes $1,171 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset and does not affect earnings.

(2) Represents the change in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2006 as follows:

Balance Sheet Classification	Non-Hedge	Hedge *(In millions)*	Total
Current-			
Other assets	$	$	$
Other liabilities			
Non-Current-			
Other deferred charges	12		12
Other noncurrent liabilities	(1,183)		(1,183)
Net Liabilities	$ (1,171)	$	$ (1,171)

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, we rely on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. We use these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of December 31, 2006 are summarized by year in the following table:

Source of Information Fair Value by Contract Year	2007	2008	2009	2010 *(In millions)*	2011	Thereafter	Total
Other external sources(1)	$ (314)	$ (257)	$ (199)	$ (191)	$	$	$ (961)

Prices based on models					(111)	(99)	(210)
Total(2)	$ (314)	$ (257)	$ (199)	$ (191)	$ (111)	$ (99)	$ (1,171)

(1) Broker quote sheets.

(2) Includes $1,171 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

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We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both our trading and non-trading derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2006. We estimate that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would not change, as the prices for all commodity positions are already above the contract price caps.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since our debt has fixed interest rates, as noted in the following table:

Comparison of Carrying Value to Fair Value

Year of Maturity	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
					(Dollars in millions)			
Assets								
Investments Other Than Cash and Cash Equivalents-								
Fixed Income						$ 236	$ 236	$ 234
Average interest rate						4.8%	4.8%	
Liabilities								
Long term Debt:								
Fixed rate	$ 33	$ 27	$ 29	$ 31	$ 32	$ 1,214	$ 1,366	$ 1,388
Average interest rate	4.7%	5.3%	5.3%	5.4%	5.6%	6.0%	6.0%	
Short-term Borrowings	$ 187						$ 187	$ 187
Average interest rate	5.6%						5.6%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $97 million and $84 million at December 31, 2006 and 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $10 million reduction in fair value as of December 31, 2006.

Outlook

Beginning in 1999, all of our customers were able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. To support customer choice, rates were restructured into unbundled service charges and additional non-bypassable charges to recover stranded costs.

Regulatory Matters

In New Jersey, laws applicable to electric industry restructuring contain provisions that are reflected in our state regulatory plan. These provisions include:

- restructuring the electric generation business and allowing customers to select a competitive electric generation supplier other than us;
- establishing or defining the provider of last resort, or PLR, obligations to customers in our service area;
- providing the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;

itemizing (unbundling) the price of electricity into its component elements including generation, transmission, distribution and stranded costs recovery charges;

continuing regulation of our transmission and distribution systems; and

requiring corporate separation of regulated and unregulated business activities.

We recognize, as regulatory assets, costs which the FERC and the NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. Our regulatory assets that do not earn a current return totaled approximately $93 million as of September 30, 2007. Regulatory assets not earning a current return will be recovered by 2014. All of our regulatory assets are expected to continue to be recovered under the provisions of the regulatory proceedings discussed below. Our regulatory assets totaled $1.8 billion as of September 30, 2007 compared to $2.2 billion as of December 31, 2006 and 2005.

We are permitted to defer for future collection from customers the amounts by which our costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of September 30, 2007 and December 31, 2006, the accumulated deferred cost balance totaled approximately $330 million and $369 million, respectively. New Jersey law allows for securitization of our deferred balance upon application and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, we filed for approval to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved our request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, our wholly-owned subsidiary, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, we filed a request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, we filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On July 18, 2006, we further requested an additional $14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the administrative law judge, or ALJ, and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual $110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that we absorb any net annual operating losses associated with our Forked River Generating Station. In the settlement, we also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds $350 million at any time after June 30, 2007.

In response to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU initiated a generic proceeding on March 16, 2006 to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the fixed price residential class. We filed our 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

In accordance with an April 28, 2004 NJBPU order, we filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, we filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Division of the Ratepayer Advocate, or DRA, filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, we filed a response to those comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact us or FirstEnergy. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders. Another revised draft was circulated by the NJBPU Staff on February 8, 2007.

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 EMP is to be developed with involvement of the Governor s Office and the Governor s Office of Economic Growth and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several state departments.

In October 2006, the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of New Jersey s electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Maintain unit prices for electricity to no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to obtain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups and major customers. EMP working groups addressing (1) energy efficiency and demand response, (2) renewables, (3) reliability and (4) pricing issues have completed their assigned tasks of data gathering and analysis and have provided reports to the EMP committee. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected later in 2007. A final draft of the EMP is expected to be presented to the Governor in late 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations.

On January 17, 2007, we filed a petition with the NJBPU seeking approval of the sale of the Forked River Generating Station to Forked River Power LLC, or FRP, which is indirectly owned by Maxim Power (USA), Inc., based upon terms and conditions set forth in the Purchase and Sale Agreement and other related agreements, including a Tolling Agreement with FirstEnergy Solutions Corp., or FES, and a PJM Agreement. FRP will assume all on-site environmental liabilities arising on and after the closing of the sale and we will retain pre-closing environmental liabilities. By order dated September 17, 2007, the NJBPU approved the sale. The New Jersey Department of the Public Advocate has appealed the order to the Appellate Division of the Superior Court of New Jersey.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the NJBPU Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments, which were due September 26, 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on our operations.

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On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule became effective on May 14, 2007. MISO, PJM and ATSI submitted tariff filings to the FERC on October 11, 2007. As a market participant in PJM, we will conform our business to PJM s revised tariff.

See Note 7 to the audited consolidated financial statements for further details and a complete discussion of regulatory matters.

Environmental Matters

We accrue environmental liabilities only when we can conclude that it is probable that we have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

We have been named as a potentially responsible party, or PRP, at waste disposal sites, which may require cleanup under the Comprehensive Environmental Responsive, Comprehension, 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 PRPs for a particular site are held liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the consolidated balance sheets as of September 30, 2007 and December 31, 2006, based on estimates of the total costs of cleanup, our proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. In addition, we have accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey. Those costs are being recovered by us through a non-bypassable societal benefits charge, or SBC. Total liabilities of approximately $60 million have been accrued through September 30, 2007.

See Note 11(B) to the audited consolidated financial statements for further details and a complete discussion of environmental matters.

Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations pending against us. The other material items not otherwise discussed above are described under Business Legal Proceedings below and in Note 11 to the audited consolidated financial statements.

Critical Accounting Policies

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States, or GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of our assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Our more significant accounting policies are described below.

Regulatory Accounting

We are subject to regulation that sets the prices (rates) we are permitted to charge our customers based on costs that the regulatory agencies determine we 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. We regularly review 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.

Revenue Recognition

We follow 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 requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts, prices in effect for each customer class and electricity provided by alternative suppliers.

Pension and Other Post-Retirement Benefits Accounting

Our reported costs of providing non-contributory qualified and non-qualified defined pension benefits and post-employment benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and other post-employment benefits, or OPEB, costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plans, and earnings on plan assets. Such factors may be further affected by business combinations, which impact employee demographics, plan experience and other factors. Pension and OPEB costs are also 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 SFAS No. 87, Employers Accounting for Pensions, or SFAS 87, 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. SFAS 87 and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions, or SFAS 106, delay 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.

As of December 31, 2006, FirstEnergy adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R), or SFAS 158, which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other post-retirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. FirstEnergy continues to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. FirstEnergy s underfunded status as of December 31, 2006 was $637 million.

In selecting an assumed discount rate, we consider 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 post-retirement benefit obligations. The assumed discount rate as of December 31, 2006 is 6.0% from 5.75% and 6.0% used as of December 31, 2005 and 2004, 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 our pension trusts. In 2006, 2005 and 2004, the FirstEnergy plan assets actually earned $567 million or 12.5%, $325 million or 8.2% and $415 million or 11.1%, respectively. FirstEnergy s pension costs in 2006, 2005 and 2004 were computed using an assumed 9.0% rate of return on plan assets which generated $396 million, $345 million and $286 million of expected return on plan assets, respectively. The 2006 expected return was based upon projections of future returns and FirstEnergy s

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pension trust investment allocation of approximately 64% equities, 29% bonds, 5% real estate, 1% private equities and 1% cash. The gains or losses generated as a result of the difference between expected and actual return on plan assets are deferred and amortized and will increase or decrease future net periodic pension expense, respectively.

FirstEnergy s pension and OPEB expense was $94 million in 2006 and $131 million in 2005. On January 2, 2007 FirstEnergy made a $300 million voluntary contribution to its pension plan (our share was $18 million). In addition during 2006, FirstEnergy amended its OPEB plan effective in 2008 to cap its monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. As a result of the $300 million voluntary contribution and the amendment to the OPEB plan effective in 2008, we expect the pension and OPEB costs for 2007 to be a credit of $94 million for FirstEnergy.

Health care cost trends have significantly increased and will affect future OPEB costs. The 2006 and 2005 composite health care trend rate assumptions are approximately 9-11%, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our portion of 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%	$ 1.7	$ 0.3	$ 2.0
Long-term return on assets	Decrease by 0.25%	$ 1.8	$ 0.4	$ 2.2
Health care trend rate	Increase by 1%	NA	$ 0.7	$ 0.7

Long-Lived Assets

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, or SFAS 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss, which is calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Asset Retirement Obligations

In accordance with SFAS No. 143, Accounting for Asset Retirement Obligations, or SFAS 143, and FIN 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143, or FIN 47, we recognize an asset retirement obligation, or ARO, for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all our long-lived assets. The ARO liability represents an estimate of the fair value of our 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. We used 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.

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. Based on the guidance provided by SFAS No. 142, Goodwill and Other Intangible Assets, or SFAS 142, we evaluate our goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment were indicated, we recognize a loss, which is calculated as the difference between the implied fair value of our goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2006, with no impairment of goodwill indicated. The forecasts used in our evaluation of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill. In 2006 and 2005, we adjusted goodwill to reverse pre-merger tax accruals due to the final resolution of tax contingencies related to the GPU acquisition. As of December 31, 2006, we had approximately $2.0 billion of goodwill.

New Accounting Standards and Interpretations Adopted

SFAS 159 The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115

In February 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company s choice to use fair value on its earnings. SFAS 159 also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157 and SFAS 107. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. We are currently evaluating the impact of SFAS 159 on our financial statements.

SFAS 157 Fair Value Measurements

In September 2006, the FASB issued SFAS 157, which establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. SFAS 157 addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value, which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those years. We are currently evaluating the impact of SFAS 157 on our financial statements.

FSP FIN 46(R)-6 Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)

In April 2006, the FASB issued FSP FIN 46(R)-6, which addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). We adopted FIN 46(R) in the first quarter of 2004, consolidating variable interest entities, or VIEs, when we are determined to be the VIE s primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FASB Staff Position, or FSP, states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1: Analyze the nature of the risks in the entity

Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. We do not expect this Statement to have a material impact on our financial statements.

FIN 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109

In June 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on our financial statements.

EITF 06-11 Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards

In June 2007, the FASB released EITF 06-11, which provides guidance on the appropriate accounting for income tax benefits related to dividends earned on nonvested share units that are charged to retained earnings under SFAS No. 123R, Share-Based Payment, or SFAS 123R. The consensus requires that an entity recognize the realized tax benefit associated with the dividends on nonvested shares as an increase to additional paid-in capital, or APIC. This amount should be included in the APIC pool, which is to be used when an entity s estimate of forfeitures increases or actual forfeitures exceed its estimates, at which time the tax benefits in the APIC pool would be reclassified to the income statement. The consensus is effective for income tax benefits of dividends declared during fiscal years beginning after December 15, 2007. EITF 06-11 is not expected to have a material impact on our financial statements.

FSP FIN 39-1 Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued FSP FIN 39-1, which permits an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement as the derivative instruments. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying the guidance in this FSP should be recognized as a retrospective change in accounting principle for all financial statements presented. We are currently evaluating the impact of this FSP on our financial statements, but it is not expected to have a material impact.

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BUSINESS

General

We are one of eight wholly-owned electric operating subsidiaries of FirstEnergy. We were organized as a corporation under the laws of the State of New Jersey in 1925 and own property and do business as an electric public utility in that state. We engage in the transmission, distribution and sale of electric energy in an area of approximately 3,200 square miles of northern, western and east central New Jersey. We also engage in the sale, purchase and interchange of electric energy with other electric companies. The area we serve has a population of approximately 2.6 million. The combined service areas of FirstEnergy operating utility subsidiaries, including us, encompass approximately 36,100 square miles in Ohio, New Jersey and Pennsylvania. The areas served have a combined population of approximately 11.3 million.

Our principal executive offices are located at 76 South Main Street, Akron, Ohio 44308. Our telephone number is (800) 736-3402.

Regulation

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influences our operating environment. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business.

Our retail rates, conditions of service, issuance of securities and other matters are subject to regulation by the NJBPU. With respect to our wholesale and interstate electric operations and rates, including regulation of our accounting policies and practices, we are subject to regulation by the FERC.

FERC and EPACT

The FERC regulates the structure and conduct of the utility industry, including regulation of accounting policies and practices. The FERC s policies affect how we operate and our costs of doing business. The EPACT, which was signed into law on August 8, 2005 by President Bush, greatly expanded the FERC s jurisdiction over the activities of public utilities, including, but not limited to, the approval of mandatory reliability standards and the prohibition of manipulative or deceptive devices or contrivances in the purchase or sale of wholesale electric energy.

Certain of the reliability standards under consideration by the FERC will apply to registered entities engaged in the generation and sale of power. The FERC proposes changes from time to time in the structure and conduct of the utility industry. The FERC s ongoing efforts to promote RTOs affects how we operate and our costs of doing business. The FERC s restructuring and deregulation-related efforts and proceedings may result in unrecoverable costs. We cannot predict the extent and timing of the FERC s policies to restructure, deregulate or re-regulate us or our industry.

Regulatory Accounting

We account for the effects of regulation through the application of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, or SFAS 71, since our 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 if the rate actions of our regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of our business that meet the above criteria. If a portion of our business applying SFAS 71 no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS No. 101, Accounting for Discontinuation of Application of SFAS 71, or SFAS 101.

In New Jersey, laws applicable to electric industry restructuring contain provisions that are reflected in our transition and regulatory plan and provide for:

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

We recognize, as regulatory assets, costs which the FERC and the NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. Regulatory assets that do not earn a current return totaled approximately $93 million as of September 30, 2007. We will recover regulatory assets not earning a current return from customers by 2014 under our transition and regulatory plan. Based on this plan, we continue to bill and collect cost-based rates for our transmission and distribution services, which remain regulated. Accordingly, it is appropriate that we continue to apply SFAS 71 to those operations. The following table discloses our regulatory assets:

Regulatory Assets	September 30, 2007	December 31, 2006	Increase (Decrease)
		(In millions)	
JCP&L	$ 1,758	$ 2,152	$ (394)

State Energy Regulation

As a competitive retail electric supplier serving retail customers in New Jersey, we are subject to state laws applicable to competitive electric suppliers. Our retail rates, conditions of service, issuance of securities and other matters are also subject to state regulation. In addition, if we or any of our subsidiaries were to engage in the construction of significant new generation facilities, they would also be subject to state siting authority.

NJBPU Rate Matters

The NJBPU is the New Jersey agency that regulates our rates, conditions of service, issuance of securities and other matters. We are permitted to defer for future collection from customers the amounts by which our costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of September 30, 2007, the accumulated deferred cost balance totaled approximately $330 million.

New Jersey law allows us to securitize our deferred balance if the NJBPU determines that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, we applied for approval to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved our request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, one of our wholly-owned subsidiaries, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

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On December 2, 2005, we filed our request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, we filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On July 18, 2006, we requested an additional $14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual $110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003 and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that we absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, we also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds $350 million any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. We filed our 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

In accordance with an April 28, 2004 NJBPU order, we filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, we filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, we filed a response to the Ratepayer Advocate s comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact us. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders. Another revised draft was circulated by the NJBPU Staff on February 8, 2007.

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 EMP is to be developed with involvement of the Governor s Office and the Governor s Office of Economic Growth and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006, the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;

- Meet 22.5% of New Jersey s electricity needs with renewable energy resources by that date;

Reduce air pollution related to energy use;

Encourage and maintain economic growth and development;

Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;

Maintain unit prices for electricity to no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and

Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to obtain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups and major customers. EMP working groups addressing (1) energy efficiency and demand response, (2) renewables, (3) reliability and (4) pricing issues have completed their assigned tasks of data gathering and analysis and have provided reports to the EMP committee. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected later in 2007. A final draft of the EMP is expected to be presented to the Governor in late 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the NJBPU Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments, which were due on September 26, 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on our operations.

Current Regulatory Proceedings

Reliability Initiatives

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (FERC, NERC and the U.S.-Canada Power System Outage Task Force) regarding enhancements to regional reliability. In 2004, we completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training and emergency response preparedness recommended for completion in 2004. On July 14, 2004, NERC independently verified that we had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions, which exceptions are now essentially complete. We are proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new equipment or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability entities may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in our service area in 2002 and 2003, the NJBPU implemented reviews into our service reliability. In 2004, the NJBPU adopted a memorandum of understanding, or MOU, which set out specific tasks related to service reliability to be performed by us and a timetable for completion and endorsed our ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a stipulation that incorporates the final report of a special reliability master, or SRM, who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The stipulation also incorporates the Executive

Summary and Recommendation portions of the final report of a focused audit of our Planning and Operations and Maintenance programs and practices. On February 11, 2005, we met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. We filed a comprehensive response to the NJBPU on July 14, 2006. We continue to file compliance reports reflecting activities associated with the MOU and stipulation.

The EPACT served, among other things, partly to amend the Federal Power Act, or FPA, by adding a new Section 215, which requires that a new ERO establish and enforce reliability standards for the bulk-power system, subject to review by the FERC. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume compliance monitoring and enforcement responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

NERC prepared the implementation aspects of reorganizing its structure to meet the FERC s certification requirements for the ERO. NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of pro forma delegation agreements with regional reliability organizations, or regional entities. The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. The regional entity may be delegated authority by the ERO, subject to FERC approval, for compliance and enforcement of reliability standards adopted by the ERO and approved by the FERC. The ERO filing was noticed on April 7, 2006, and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified NERC as the ERO to implement the provisions of Section 215 of the FPA and directed NERC to make compliance filings addressing governance and non-governance issues and the regional delegation agreements. On September 18, 2006 and October 18, 2006, NERC submitted compliance filings addressing the governance and non-governance issues identified in the FERC ERO Certification Order, dated July 20, 2006. On October 30, 2006, the FERC issued an order accepting most of NERC s governance filings. On January 18, 2007, the FERC issued an order largely accepting NERC s compliance filings addressing non-governance issues, subject to an additional compliance filing requirement.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards, as well as for approval with the relevant Canadian authorities. These reliability standards are based, with some modifications and additions, on the current NERC Version 0 reliability standards. The reliability standards filing was subsequently evaluated by the FERC on May 11, 2006, leading to the FERC Staff s release of a preliminary assessment that cited many deficiencies in the proposed reliability standards. NERC and industry participants filed comments in response to the Staff s preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a notice of proposed rulemaking, or NOPR, on the proposed reliability standards on October 20, 2006. In the NOPR, the FERC proposed to approve 83 of the 107 reliability standards and directed NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not approved remained pending at the FERC awaiting further clarification and filings by NERC and regional entities. The FERC also provided additional clarification within the NOPR regarding the proposed application of final standards and guidance with regard to technical improvements of the standards. On November 15, 2006, NERC submitted several revised reliability standards and three new proposed reliability standards. Interested parties were provided the opportunity to comment on the NOPR (including the revised standards submitted by NERC in November) by January 3, 2007. Numerous parties, including FirstEnergy, filed comments on the NOPR on January 3, 2007. In a separate order issued October 24, 2006, the FERC approved NERC s 2007 budget and business plan subject to certain compliance filings.

To date, the FERC has approved 83 of the 107 reliability standards proposed by NERC. Nevertheless, the FERC has directed NERC to submit improvements to 56 of the 83 approved standards and has endorsed NERC s process for developing reliability standards and its associated work plan. On May 4, 2007, NERC submitted 24 proposed Violation Risk Factors that would operate as a system of weighting the risk to the power grid associated with a particular reliability standard violation. The FERC issued an order approving 22 of those factors on June 26, 2007.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards became effective throughout 2006 and will become effective throughout 2007. NERC filed these proposed standards with the FERC and relevant Canadian authorities for approval. The cyber security standards were not included in the October 20, 2006 NOPR and are being addressed in a separate FERC docket. On December 11, 2006, the FERC Staff provided its preliminary assessment of the cyber security standards and cited various deficiencies in the proposed standards. Numerous parties, including FirstEnergy, provided comments on the preliminary assessment. The standards remain pending before the FERC. Separately, on July 20, 2007, the FERC issued a NOPR proposing to adopt eight related Critical Infrastructure Protection Reliability Standards. On October 5, 2007, numerous parties, including FirstEnergy, provided comments on the proposed Critical Infrastructure Protection standards. These standards, and FirstEnergy s comments thereon, are pending before the FERC.

On November 29, 2006, NERC submitted an additional compliance filing with the FERC regarding the Compliance Monitoring and Enforcement Program, or CMEP, along with the proposed Delegation Agreements between the ERO and the regional reliability entities. The FERC provided opportunity for interested parties to comment on the CMEP by January 10, 2007. FirstEnergy, as well as other parties, moved to intervene and submitted responsive comments on January 10, 2007. Subsequently, the FERC certified NERC as the ERO, approved the CMEP and approved a set of reliability standards, which became mandatory and enforceable on June 18, 2007 with penalties and sanctions for noncompliance.

The ECAR, MAAC and the MAIN reliability councils completed the consolidation of these regions into a single new regional reliability organization known as Reliability*First* Corporation, or RFC. RFC began operations as a regional reliability council under NERC on January 1, 2006, and on November 29, 2006, filed a proposed Delegation Agreement with NERC to obtain certification consistent with the final rule as a regional entity under the ERO. All of our facilities are located within the RFC region.

We believe we are in compliance with all current NERC reliability standards. However, based upon a review of the FERC s guidance to NERC in its March 16, 2007 Final Rule on Mandatory Reliability Standards, it appears that the FERC may eventually adopt stricter standards than those just approved. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If we are unable to meet the reliability standards for our bulk-power system in the future, it could have a material adverse effect on our financial condition, results of operations and cash flows.

On April 18-20, 2007, RFC performed a routine compliance audit of FirstEnergy s bulk-power system within the MISO region and found FirstEnergy to be in full compliance with all audited reliability standards. Similarly, RFC has scheduled a compliance audit of FirstEnergy s bulk-power system within the PJM region in 2008. We do not expect any material adverse impact to our financial condition as a result of these audits.

FERC Rate Matters

On November 18, 2004, the FERC issued an order eliminating the regional through and out rates, or RTOR, for transmission service between the Midwest Independent System Transmission Operator, Inc., or MISO, and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a seams elimination cost adjustment, or SECA, mechanism to recover lost RTOR revenues during a 16-month transition period from LSEs. The FERC issued orders in 2005 setting the SECA for hearing. We, ATSI, Met-Ed, Penelec and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in the fourth quarter of 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. We, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas & Electric Company, or BG&E, and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. Hearings were held and numerous parties appeared and litigated various issues; including American Electric Power Company, Inc., or AEP, which filed in opposition proposing to create a postage stamp rate for high voltage transmission facilities across PJM. At the conclusion of the hearings, the ALJ issued an initial decision adopting the FERC Trial Staff s position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. Numerous parties, including FirstEnergy, submitted briefs opposing the ALJ s decision and recommendations. On April 19, 2007, the FERC issued an order rejecting the ALJ s findings and recommendations in nearly every respect. The FERC found that the PJM transmission owners existing license plate 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, the FERC directed that costs for new transmission facilities that are rated at 500 kilovolts, or kV, or higher are to be socialized throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a beneficiary pays basis. Nevertheless, the FERC found that PJM s current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM s tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC s April 19, 2007 Order. Subsequently, FirstEnergy and other parties filed pleadings opposing the requests for rehearing. The FERC s Orders on PJM rate design, if sustained on rehearing and appeal, will prevent the allocation of the cost of existing transmission facilities of other utilities to us. In addition, the FERC s decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce future transmission costs shifting to our zones.

New FERC Transmission Rate Design Filings

On August 1, 2007, a number of filings were made with the FERC by transmission owning utilities in the MISO and PJM footprint that could affect the transmission rates paid by us.

FirstEnergy joined in a filing made by the MISO transmission owners that would maintain the existing license plate rates for transmission service within MISO provided over existing transmission facilities. FirstEnergy also joined in a filing made by both the MISO and PJM transmission owners proposing to continue the elimination of transmission rates associated with service over existing transmission facilities between MISO and PJM. If adopted by the FERC, these filings would not affect the rates charged to load-serving FirstEnergy affiliates for transmission service over existing transmission facilities. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV transmission facilities across the entire MISO footprint be maintained (known as the RECB Process). Each of these filings was supported by the majority of transmission owners in either MISO or PJM, as applicable.

The Midwest Stand-Alone Transmission Companies made a filing under Section 205 of the FPA requesting that 100% of the cost of new qualifying 345 kV transmission facilities be spread throughout the entire MISO footprint. Further, Indianapolis Power and Light Company separately moved the FERC to reopen the record to address the cost allocation for the RECB Process. If either proposal is adopted by the FERC, it could shift a greater portion of the cost of new 345 kV transmission facilities to the FirstEnergy footprint in MISO and increase the transmission rates paid by load-serving FirstEnergy affiliates in MISO.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the FPA seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable and unduly discriminatory, and to have FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM SuperRegion that regionalizes the cost of new and existing transmission facilities operated at voltages of 345 kV and above. Lower voltage facilities would continue to be recovered in the host utility transmission rate zone through a license plate rate. AEP requests a refund effective October 1, 2007, or alternatively, February 1, 2008. The effect of this proposal, if adopted by the FERC, would be to shift significant costs to the FirstEnergy zones in MISO and PJM. FirstEnergy believes that most of these costs would ultimately be recoverable in retail rates. On October 12, 2007, BG&E filed a motion to dismiss AEP s complaint. On October 16, 2007, the Organization of MISO States filed comments urging the FERC to dismiss AEP s complaint. Interventions and protests to AEP s complaint and answers to BG&E s motion to dismiss were due by October 29, 2007. FirstEnergy and other transmission owners filed protests to AEP s complaint and support for BG&E s motion to dismiss. AEP has asked for consolidation of its complaint with the cases above, and we expect it to be resolved on the same timeline as those cases.

Any increase in rates charged for transmission service to FirstEnergy affiliates is dependent upon the outcome of these proceedings at the FERC. All or some of these proceedings may be consolidated by the FERC and set for hearing. The outcome of these cases cannot be predicted. Any material adverse impact on us would depend upon the ability of the load-serving FirstEnergy affiliates to recover increased transmission costs in their retail rates. Increased transmission charges in our transmission zone would be the responsibility of competitive electric retail suppliers, including FES.

MISO Ancillary Services Market and Balancing Area Consolidation Filing

MISO made a filing on September 14, 2007 to establish Ancillary Services markets for regulation, spinning and supplemental reserves, to consolidate the existing 24 balancing areas within the MISO footprint and to establish MISO as the NERC registered balancing authority for the region. An effective date of June 1, 2008 was requested in the filing.

MISO s previous filing to establish an Ancillary Services market was rejected without prejudice by the FERC on June 22, 2007, subject to MISO making certain modifications in its filing. We believe that MISO s September 14 filing generally addresses the FERC s directives. FirstEnergy supports the proposal to establish markets for Ancillary Services and consolidate existing balancing areas, but filed objections on specific aspects of the MISO proposal. Interventions and protests to MISO s filing were made with the FERC on October 15, 2007.

Order No. 890 on Open Access Transmission Tariffs

On February 16, 2007, the FERC issued a final rule (Order No. 890) that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement and provide for a more open and coordinated transmission planning process. The final rule became effective on May 14, 2007. MISO, PJM and ATSI will be filing revised tariffs to comply with the FERC s Order. MISO, PJM and ATSI submitted tariff filings to the FERC on October 11, 2007. As a market participant in PJM, we will conform our business practices to each respective revised tariff.

Environmental Matters

We accrue environmental liabilities only when we conclude that it is probable that we have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

We have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous

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substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. We have accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by us through a non-bypassable SBC. We have accrued liability of approximately $60 million through September 30, 2007.

Capital Requirements

Our capital expenditures are $192 million for 2007 and expected to be $1.144 billion for the years 2008-2011. Such costs include expenditures for the improvement of existing facilities and for the construction of transmission lines, distribution lines, substations and other assets. The maturities of, and sinking fund requirements for, our long-term debt are $33 million for 2007 and $119 million for the years 2008-2011. Our operating lease commitments are $8 million for 2007 and $32 million for the years 2008-2011.

The extent and type of future financings will depend on the need for external funds as well as market conditions and the maintenance of an appropriate capital structure. We will continue to monitor financial market conditions and, where appropriate, may take advantage of economic opportunities to refund debt to the extent that our financial resources permit.

Because we satisfied the provision of our senior note indenture for the release of all FMB held as collateral for senior notes in May 2007, we are no longer required to issue FMB as collateral for senior notes and therefore are not limited as to the amount of senior notes we may issue.

As of September 30, 2007, we have redeemed all of our outstanding preferred stock. As a result of this redemption, the applicable earnings coverage test in our charter is inoperative. In the event that we issue preferred stock in the future, the earnings coverage test will govern the amount of preferred stock that may be issued.

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

System Capacity and Reserves

Our 2006 net maximum hourly demand was 6,702 MW on August 2, 2006. Our load is supplied through the New Jersey BGS auction process, transferring substantially all of our load obligation to other parties. Our current capacity portfolio contains long-term purchases from New Jersey NUGs.

Competition

We compete with other utilities for intersystem bulk power sales and for sales to municipalities and cooperatives. We also compete with suppliers of natural gas and other forms of energy in connection with their industrial and commercial sales and in the home climate control market, both with respect to new customers and conversions, and with all other suppliers of electricity. To date, there has been no substantial cogeneration by the our customers.

As a result of actions taken by state legislative bodies over the last few years, major changes in the electric utility business have occurred in parts of the United States, including New Jersey. These changes have resulted in fundamental alterations in the way traditional integrated utilities and holding company systems, like FirstEnergy, conduct their business.

Our obligation to provide BGS has been removed through a transitional mechanism of auctioning the obligation. See NJBPU Rate Matters above.

Research and Development

We participate in funding the Electric Power Research Institute, or EPRI, which was formed for the purpose of expanding electric research and development under the voluntary sponsorship of the nation s electric utility industry public, private and cooperative. Its goal is to mutually benefit utility companies and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. The EPRI conducts research on all aspects of electric power production and use, including fuels, generation, delivery, energy management and conservation, environmental effects and energy analysis. The major portion of EPRI research and development projects is directed toward practical solutions and their applications to problems currently facing the electric utility industry.

Employees

As of September 30, 2007, we had 1,462 employees, of whom 1,133 were covered by collective bargaining agreements.

Our bargaining unit employees filed a grievance challenging our 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, our appeal of the award filed on October 18, 2005. The arbitration panel provided additional rulings regarding damages during a September 2007 hearing, and it is anticipated that he will issue a final order in late 2007. We intend to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. We recognized a liability for the potential $16 million award in 2005.

Properties

As of December 31, 2006, our distribution and transmission systems consist of the following:

Distribution Lines	Transmission Lines	Substation Transformer Capacity
(Miles)		*(kV-amperes)*
18,966	2,135	20,964,000

We provide for depreciation on a straight-line basis at various rates over the estimated lives of our property included in plant in service. Our annual composite rates for our electric plant in 2006, 2005 and 2004 is shown in the following table:

Annual Composite Depreciation Rate		
2006	**2005**	**2004**
2.1%	2.2%	2.1%

We hold a 50% ownership interest in Yard s Creek, a 200-MW electrical power generating plant located in Blairstown Township, New Jersey. As of December 31, 2006, the Yard s Creek pumped storage facility had a net book value of approximately $20 million. Our transmission facilities are physically interconnected with the transmission facilities of Met-Ed and Penelec and are operated on an integrated basis as part of the PJM RTO.

Legal Proceedings

We are involved in various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations. The other material items not otherwise discussed above are described below.

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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 our territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey s electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, we provided unsafe, inadequate or improper service to our customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against us, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in our territory.

In August 2002, the trial court granted partial summary judgment to us and dismissed the plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation and strict product liability. In November 2003, the trial court granted our motion to decertify the class and denied plaintiffs motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision on July 8, 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of our transformers in Red Bank, New Jersey, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period.

In 2005, we renewed our motion to decertify the class based on a very limited number of class members who incurred damages. We also filed a motion for summary judgment on the remaining plaintiffs claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. The plaintiffs appealed this ruling to the New Jersey Appellate Division, which reversed the decertification of the Red Bank class on March 7, 2007 and remanded the matter back to the Trial Court to allow the plaintiffs sufficient time to establish a damage model or individual proof of damages. We filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court, which was denied on May 9, 2007. Proceedings are continuing in the Superior Court. We are defending this class action lawsuit, but are unable to predict the outcome of this matter. No liability has been accrued as of September 30, 2007.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in our service area. The U.S.-Canada Power System Outage Task Force s final report issued in April 2004 concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and the ECAR to assess and understand perceived inadequacies within our system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy s website (www.doe.gov).

We believe that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. We remain convinced that the outages cannot be explained by events on any one utility s system. The final report contained 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations related to broad industry or policy matters, while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, the ECAR and other parties to correct the causes of the August 14, 2003 power outages.

FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of our electric system. The implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy is also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City, New Jersey from an electrical power outage. None of FirstEnergy s subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the court granted FirstEnergy s motion to dismiss. The plaintiff has not appealed.

We are defending these legal actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against us. Although we are unable to predict the impact of these proceedings, if we were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Other Legal Matters

Our bargaining unit employees filed a grievance challenging our 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, our appeal of the award filed on October 18, 2005. The arbitration panel provided additional rulings regarding damages during a September 2007 hearing, and it is anticipated that the arbitration panel will issue a final order in late 2007. We intend to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. We recognized a liability for the potential $16 million award in 2005.

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MANAGEMENT

Set forth below is the name, age, position and a brief account of the business experience of each of our executive officers and directors and key employees.

Name	Age	Position(s)
Stephen E. Morgan	57	President and Director
Paulette R. Chatman	54	Controller
Randy Scilla	53	Treasurer
Edward J. Udovich	52	Corporate Secretary
Donald M. Lynch	53	Regional President
Bradley S. Ewing	47	Director
Mark A. Julian	50	Director
Gelorma E. Persson	76	Director
Donald R. Schneider	46	Director
Jesse T. Williams, Sr	67	Director

Stephen E. Morgan has served as President since January 2004 and Director since September 2003. Prior to his appointment as President, Mr. Morgan served as Vice President Energy Delivery of FirstEnergy from October 2002 until January 2002 and as Regional President Central of FirstEnergy from January 2002 until September 2002.

Paulette R. Chatman has served as Controller since July 2007. Prior to her appointment as Controller, Ms. Chatman served as Assistant Controller from November 2001 until July 2007. Ms. Chatman has also served as Assistant Controller of FESC and various FirstEnergy subsidiaries since November 2001.

Randy Scilla has served as Treasurer since July 2007. Prior to his appointment as Treasurer, Mr. Scilla served as Assistant Treasurer from November 2001 until July 2007. Mr. Scilla has also served as Assistant Treasurer of FESC and various other FirstEnergy subsidiaries since January 1999.

Edward J. Udovich has served as Corporate Secretary since July 2007. Prior to his appointment as Corporate Secretary, Mr. Udovich served as Assistant Corporate Secretary from November 2001 until July 2007. Mr. Udovich has also served as Corporate Secretary of FESC and various other FirstEnergy subsidiaries since June 1998.

Donald M. Lynch has served as Regional President since June 2004. Mr. Lynch served as FESC s Regional President Central from November 2001 until January 2004.

Bradley S. Ewing has served as Director since January 2004. Mr. Ewing has served as FESC s Vice President Energy Delivery since 2004. From 1999 to 2004, Mr. Ewing served as Director of Operations Services Northern Region.

Mark A. Julian has served as Director since January 2004. Mr. Julian has served as FESC s Vice President Energy Delivery since 2003. From 2001 to 2003, Mr. Julian served as Director of Energy Delivery Technical Services.

Gelorma E. Persson has served as Director since July 1983. Ms. Persson has served in the New Jersey Division of Consumer Affairs Elder Fraud Investigation Unit since 1999. She previously served as liaison (Special Assistant Director) between the New Jersey Division of Consumer Affairs and various state boards. Prior to 1995, she was owner and President of Business Dynamics Associated of Red Bank, New Jersey. Ms. Persson is a member of the United States Small Business Administration National Advisory Board, the New Jersey Small Business Advisory Council, the Board of Advisors of Brookdale Community College and the Board of Advisors of Georgian Court College.

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Donald R. Schneider has served as Director since March 2007. Mr. Schneider serves as Senior Vice President Energy Delivery and Customer Service of FESC and various other FirstEnergy operating subsidiaries. Prior to his appointment as Vice President Energy Delivery in 2006, Mr. Schneider served as Vice President Commodity Operations of FES from October 2004 until June 2006 and as Vice President Fossil Operations of FES from January 2002 until May 2004.

Jesse T. Williams, Sr. has served as Director since July 2007. Mr. Williams has also served as a Director of FirstEnergy since 1997 and Director of OE from 1992-1997. Mr. Williams retired in 1998 as Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company, a manufacturer of tire and rubber related products.

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EXECUTIVE COMPENSATION

General

FirstEnergy designs, evaluates and administers all compensation plans for us and other subsidiaries. FirstEnergy s Board of Directors and/or FirstEnergy s Compensation Committee reviews and approves all compensation for FirstEnergy and its subsidiaries, including us. The role of our Board of Directors is to carry out the activities generally performed by a Board of Directors and make decisions with regard to our operational and financial aspects. Our Board of Directors does not make compensation decisions for our employees and it does not have a separate Compensation Committee. However, our Board of Directors does make compensation decisions relating to our director compensation. References in this prospectus to the Compensation Committee mean the Compensation Committee of the FirstEnergy Board of Directors.

Compensation disclosure is provided for the following named executive officers: Anthony J. Alexander, Richard R. Grigg, Richard H. Marsh, Stephen E. Morgan and Leila L. Vespoli. Mr. Morgan served as our President and Chief Executive Officer, or CEO, in 2006. Mr. Marsh served as our Senior Vice President and Chief Financial Officer in 2006. Ms. Vespoli served as our Senior Vice President and General Counsel in 2006. Since we are a wholly-owned subsidiary of FirstEnergy, certain executive officers of FirstEnergy, in addition to Mr. Morgan and Mr. Marsh, perform primary policymaking functions for us. Mr. Anthony J. Alexander, President and CEO of FirstEnergy, and Mr. Richard R. Grigg, Executive Vice President and Chief Operating Officer, or COO, of FirstEnergy, and Ms. Leila L. Vespoli, Senior Vice President and General Counsel, were the three most highly compensated executive officers of FirstEnergy in 2006 who also exercised policymaking functions for us.

Compensation Discussion and Analysis

FirstEnergy provides a competitive compensation program to attract, retain and reward employees whose performance and contributions drive FirstEnergy s success. The compensation philosophy targets total compensation at the market median for FirstEnergy s peer group, with the opportunity to earn above-median compensation for strong company and/or individual performance. As a result, the executive compensation program is intended to reward and retain executives responsible for leading the organization in the achievement of business objectives in the complex energy services industry.

FirstEnergy s compensation programs apply to all executives and reflect the following principles:

- Total compensation is competitive and reflects a pay-for-performance orientation.
- The peer group used to evaluate competitive levels of compensation is comprised of comparable energy services companies.
- Base salaries are generally targeted at or near the median of the peer group.
- Incentive opportunities are targeted at the median competitive level for the achievement of specified corporate goals and include the opportunity to achieve above median compensation rewards.
- Short-term incentive opportunities are based on a combination of corporate and business unit goals.
- Long-term incentive awards are based on both FirstEnergy s absolute performance and performance relative to peer companies.

The elements of FirstEnergy s compensation program include base salary and short-term and long-term incentive opportunities. Under FirstEnergy s pay-for-performance philosophy, executive rewards are directly linked to short-term and long-term results for key stakeholders, including shareholders and customers. A significant portion of an executive s actual pay reflects corporate and business unit performance as defined by various financial and operational measures.

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Variations of base salary from median levels for individual executives reflect the relative responsibilities of the position and facilitate internal equity. Further, base salaries reflect the executive s qualifications, experience and sustained performance level.

Short-term incentive opportunities provide executives the potential to achieve total cash compensation at approximately the 75th percentile of the peer group if corporate performance is superior. However, there is significant risk if performance is below expectations. As an executive s responsibility increases, a greater percentage of the annual incentive is driven by corporate performance. Corporate goals reflect targeted performance objectives for the year and are heavily weighted toward financial targets.

Long-term incentive awards consisting of restricted stock units and performance shares are based on the achievement of corporate goals and the annualized total shareholder return generated by FirstEnergy common stock over a three-year period relative to a peer group, respectively.

The components of the compensation programs are evaluated both individually and in the aggregate. Fundamentally, the proportion of pay at risk increases as an executive s responsibilities increase. Thus, executives with greater responsibilities for the achievement of company performance targets bear a greater risk if those goals are not achieved and also receive a greater reward if the goals are met or surpassed. The appropriate balance of annual, medium-term and longer-term incentives facilitates the retention of talented executives, recognizes the achievement of short-term goals, rewards long-term strategic results and encourages equity ownership. In determining compensation, the Compensation Committee balances the pay to achieve competitive parity with the amount required to retain and motivate executives. FirstEnergy s philosophy is to use a variety of compensation vehicles, primarily driven by financial and operational performance metrics.

As is indicated in the following chart, as the level of responsibility increases, the percentage of base salary decreases and the percentage of at-risk pay, including short-term incentive and equity, increases. The chart represents the actual percentage of each pay element in relation to total target compensation for the named executives in 2006.

Named Executive Officer	Base Salary	Short-term Incentive	Equity
Anthony J. Alexander	19%	19%	62%
Richard R. Grigg	30%	22%	48%
Richard H. Marsh	34%	22%	44%
Stephen E. Morgan	48%	21%	31%
Leila L. Vespoli	36%	21%	43%

Although the Compensation Committee has established share ownership guidelines for executives, such equity ownership is not considered when establishing compensation levels. However, the Compensation Committee does review prior awards, both vested and unvested, on a regular basis through the use of the tally sheets described below.

Compensation Setting Process

Consultant

The Compensation Committee employs an independent, external compensation consultant at FirstEnergy s expense. Consistent with NYSE rules, the Compensation Committee has the sole authority to retain and dismiss the consultant and to approve the consultant s fees. The consultant provides objective, independent advice and analysis to the Compensation Committee with respect to executive and director compensation. During 2006, the Compensation Committee conducted a review of executive compensation consultants as part of its due diligence. In September 2006, the Compensation Committee retained Hewitt Associates based on its expertise,

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independence and utility industry experience. The Compensation Committee concluded that Hewitt Associates would better serve FirstEnergy and its Board of Directors at this time than the previous consultant. Management uses Hewitt Associates to provide compensation, actuarial and benefit plan consulting services to FirstEnergy and advises the Compensation Committee of the work performed by Hewitt. The Compensation Committee determined that these relationships do not impair the ability of the consultant to render impartial services to the Compensation Committee.

The Compensation Committee relies on the consultant to provide an annual review of executive compensation practices at other companies. This review includes companies that FirstEnergy competes with for executive talent and is further discussed under Benchmarking below. This review encompasses base pay, annual incentives, long-term incentives and perquisites. In addition, the Compensation Committee may request advice concerning the design, communication and implementation of incentive plans or other compensation programs. The services provided by the consultant in 2006 included:

- A review of the alignment of executive compensation practices to FirstEnergy s compensation philosophy;
- Benchmarking and analysis of competitive compensation practices for executives and directors;
- Advice related to the modification of incentive programs for executive officers and other key employees;
- A review of FirstEnergy s severance agreements to ensure alignment with competitive practices; and
- Advice and guidance regarding the impact new rules and regulations would have on FirstEnergy s compensation programs.

Benchmarking

As referenced under Consultant above, in early 2006, the Compensation Committee s consultant compared company executive compensation against 24 large utilities in the United States. These are generally the energy services organizations that FirstEnergy competes with for executive talent. The consultant identified the following peer group:

Allegheny Energy	Ameren	American Electric Power
CenterPoint Energy	CMS Energy	Consolidated Edison
DTE Energy	Dominion Resources	Duke Energy
Edison International	Energy East	Entergy
Exelon	FPL Group	PG&E
PPL	Pepco	Pinnacle West
Progress Energy	Sempra Energy	Southern Company
TECO Energy	TXU	Xcel Energy

Targeted base pay and short-term and long-term incentive opportunities are based on a review of the compensation of these companies. Since FirstEnergy is larger than the typical firm in the sample, results were adjusted based on revenues to make the comparison relevant. In addition, consideration may be given to broader general industry data when that is the relevant pool in which FirstEnergy competes for talent. The consultant evaluated the competitive data and provided recommendations for FirstEnergy consistent with FirstEnergy s compensation philosophy.

The elements of compensation as stated and defined later, and the mix of the elements are determined based on an annual analysis of these peer companies. The Compensation Committee has determined that the compensation elements, both individually and in the aggregate, are appropriately aligned with FirstEnergy s compensation philosophy.

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Management and/or the Compensation Committee reviews the compensation philosophy annually to ensure that it continues to align with company goals and offers competitive levels of compensation. FirstEnergy s recent success in filling executive positions from the external market, its relatively low executive turnover and its success with ongoing recruitment efforts indicate FirstEnergy s compensation programs are meeting the goal of providing competitive pay.

Tally Sheets

The Compensation Committee reviewed a comprehensive summary of all components of compensation, including base salary, incentive awards based on corporate and business unit performance, equity compensation, stock option and restricted stock performance, perquisites and other personal benefits, and actual and projected payout obligations under several termination scenarios (i.e., voluntary resignation, retirement, severance and change in control) for the named executive officers of FirstEnergy, including Mr. Marsh, Mr. Alexander, Mr. Grigg and Ms. Vespoli. Based on the review of these tally sheets, the Compensation Committee determined that the total compensation provided (and, in the case of termination scenarios, the potential payout) was reasonable. The Compensation Committee performs this review at each January meeting. The Compensation Committee did not review tally sheets for Mr. Morgan, as he was not one of FirstEnergy s five highest paid executive officers in 2006.

Role of Executives

Our executives are not involved in planning, setting or determining compensation. FirstEnergy s Board of Directors has delegated authority to Anthony J. Alexander, CEO of FirstEnergy, to establish the compensation of other senior executives whose compensation is not determined by the Compensation Committee pursuant to its charter, provided that this authority is exercised only after consultation with the Compensation Committee. As such, the CEO makes recommendations to the Compensation Committee for these other executives total compensation. In all cases, these recommendations are presented to the Compensation Committee for review.

The CEO and other senior executives of FirstEnergy play an increased role in the early stages of design and evaluation of compensation programs and policies. The executives review, discuss and provide comments when FirstEnergy is planning a design change to a compensation program. They have a vested interest in ensuring that the compensation programs and policies will engage employees and provide incentives to strive for excellence in their daily responsibilities in order to produce outstanding financial and operating results for FirstEnergy and its shareholders.

Elements of Compensation

Base Salary

Executives are paid a base salary for performing their job responsibilities. The Compensation Committee reviews executives base salaries annually. Adjustments to base salary are made, if appropriate, generally on March 1 of each year, after considering factors such as company performance, individual performance, changes in executives responsibilities and changes in the competitive marketplace. The consultant provides the median competitive data for each executive s position as described above. Generally, a range of 85% to 115% of this competitive data is used to promote the pay-for-performance philosophy. The base salaries for all named executive officers fall within this range.

On March 1, 2007, the Compensation Committee provided Mr. Morgan with a lump sum award of $15,000 in lieu of a base salary increase. The Compensation Committee provided base salary increases of 7.45%, 4.0%, 5.26% and 7.53% for Mr. Marsh, Mr. Alexander, Mr. Grigg and Ms. Vespoli respectively, based on the results of the annual compensation review.

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Short-Term Incentive Program

FirstEnergy s short-term incentive program, or STIP, provides awards to executives whose contributions support the achievement of corporate financial and operational goals. The program supports FirstEnergy s compensation philosophy by linking executive awards directly to annual performance results on key corporate and business unit objectives. Similar to base salaries, the STIP provides executives with opportunities targeted to the median of the utility industry. The Compensation Committee annually reviews these target award opportunities, which are expressed as a percentage of base salary. During the first quarter, adjustments to target levels for the current year are made as appropriate and warranted by competitive market practice and internal equity considerations.

FirstEnergy s STIP is based on performance targets, and in 2006 these included, but were not limited to, objectives relative to the following goals:

- Earnings per share;
- Free cash flow from operations;
- Customer service excellence;
- Megawatt generation output;
- Transmission outage frequency;
- Distribution System Average Interruption Duration Index;
- Financial contribution to earnings;
- Safety (including nuclear safety); and
- Workforce hiring.

Executives are assigned and evaluated on goals applicable to their responsibilities within the organization. These performance goals were chosen because they have a significant impact on FirstEnergy s operational and financial success. The specific targets for these performance goals reflect FirstEnergy s confidential strategic plans and are not disclosed publicly for competitive reasons. FirstEnergy establishes targets for incentive compensation performance measures based on earnings growth aspirations and achieving continuous improvement in operational performance to reach industry top quartile/decile levels. Over the last five years, FirstEnergy has achieved target performance levels for the performance measures held by senior executives approximately 56% of the time. The weightings of financial and operational targets for executives are determined at the beginning of each year. The following represents the financial and operational targets assigned to each named executive officer in 2006:

Named Executive Officer	Financial	Operational
Anthony J. Alexander	80%	20%
Richard H. Marsh	70%	30%

Stephen E. Morgan	50%	50%
Richard R. Grigg	60%	40%
Leila L. Vespoli	50%	50%

The process for allocating awards is similar for all executives. The target levels are established in February, and performance is measured throughout the year. In 2006, STIP target award opportunities for the named executive officers ranged from 45% of salary to 100% of salary. Awards for the short-term incentive based on operational performance range from 50% of target for performance at the threshold level to 150% of target for outstanding performance. Awards for the short-term incentive portion based on financial performance range from 50% of target for performance at threshold to a maximum of 200% of target for outstanding performance. Awards are not made if threshold performance is not achieved. Awards are mathematically interpolated for performance between threshold and maximum and no positive or negative discretion is applied to the final awards. The Compensation Committee has no authority to adjust upwards the amount payable to a covered employee with respect to a particular award.

In 2006, we and FirstEnergy achieved outstanding financial and operational performance relative to our goals, which had a positive impact on the short-term incentive payout. For 2006, Mr. Morgan s award was $184,359. The remaining named executive officers awards were as follows: Alexander $2,000,000; Grigg $874,086; Marsh $514,003; and Vespoli $435,414.

Long-Term Incentive Program

Long-term incentive awards are awarded under the terms of the FirstEnergy Executive and Director Incentive Compensation Plan, or the Incentive Plan. The long-term incentive program, or LTIP, is designed to reward executives for achievement of company goals, which ultimately result in increased shareholder value. This program is equity-based to align the long-term interests of executives with those of shareholders. In 2006, FirstEnergy delivered long-term incentives through a combination of restricted stock units and performance shares. FirstEnergy has not issued stock options under its LTIP since 2004. Similar to the STIP, during the first quarter of each year the Compensation Committee reviews and adjusts executives long-term incentive target opportunities as appropriate and warranted by competitive market practice and internal equity considerations. The Compensation Committee has no authority to adjust upwards the amount payable to a covered employee with respect to a particular award.

FirstEnergy s restricted stock unit program contains two components: performance-adjusted and discretionary restricted stock units. Performance-adjusted restricted stock units are designed to focus participants on key financial and operational metrics that drive FirstEnergy s success, foster management ownership and aid retention. These metrics are earnings per share, safety and an operational performance index. The actual number of shares issued may be adjusted upward or downward by 25% based on FirstEnergy s performance against these three key metrics. The specific targets for these metrics reflect FirstEnergy s confidential strategic plans and are not disclosed publicly for competitive reasons.

Performance-adjusted restricted stock units are granted to all eligible executives. Based on competitive analysis, each eligible executive received an initial grant of performance-adjusted restricted stock units, at a target level based on the executive s annual salary as of March 1, 2006, and calculated using the average of the high and low stock price on March 1, 2006. These performance-adjusted restricted stock units are granted to each executive with the right to receive shares of FirstEnergy common stock at the end of the three-year restriction period. In 2006, performance-adjusted restricted stock grants were issued as follows: Alexander 47,295 units; Grigg 14,926 units; Marsh 6,000 units; Morgan 2,372 units; and Vespoli 5,023 units.

Discretionary restricted stock units are granted in limited circumstances to high performing and/or high potential employees or to retain critical talent. Discretionary restricted stock units do not have a performance component. These discretionary restricted stock units are granted to each executive with the right to receive shares of FirstEnergy common stock at the end of the five-year restriction period. In 2006, Mr. Marsh was granted 4,910 discretionary restricted stock units.

FirstEnergy s performance share program provides executives with the opportunity for awards based on FirstEnergy s total shareholder return over a three-year period relative to the Edison Electric Institute s Index of Investor-Owned Electric Utility Companies, or EEI Index. The number of performance shares granted is calculated by multiplying the executive s March 1 salary by the eligible incentive percent and dividing by the average high and low common stock price during December of the previous year. Performance share grants in 2006 were issued as follows: Alexander 31,850 shares; Grigg 9,408 shares; Marsh 4,848 shares; Morgan 2,135 shares; and Vespoli 4,797 shares.

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Performance shares typically payout in cash at the end of the performance cycle. For the three-year period ending December 2006, FirstEnergy ranked 8th out of 63 companies in the EEI Index, which positively impacted the performance share payout. The performance shares for the 2004-2006 period were paid as follows: Alexander $2,536,266; Marsh $593,655; Morgan $283,238; and Vespoli $565,046. Mr. Grigg did not receive a payout because he was not employed by FirstEnergy in January 2004 when the grants were issued. Based on the terms defined in the Incentive Plan the amount payable in cash in a calendar year to any participant pursuant to any performance share award may not exceed $2,000,000. Mr. Alexander s award was paid as follows: $2,000,000 in cash and $536,266 in FirstEnergy common stock.

The process for allocating awards is similar for all executives. The target levels are established in February, and performance is measured throughout the cycle. In 2006, performance-adjusted restricted stock unit target award opportunities for the named executive officers ranged from 35% of salary to 195% of salary. In 2006, performance share target award opportunities for the named executive officers ranged from 30% of salary to 125% of salary. The mix of the types and the range of the awards are established based on competitive benchmarking and are intended to encourage operational excellence and to increase shareholder value.

Payment of restricted stock units and performance shares upon termination from FirstEnergy are discussed under Post-Termination Compensation and Benefits below. All long-term incentive awards granted to the named executive officers are subject to the share ownership guidelines discussed under Stock Ownership/Retention Guidelines below.

The Compensation Committee has determined that an equity grant date of March 1 is appropriate for restricted stock units. Performance shares are granted effective January 1. The timing of the grants enables FirstEnergy to consider competitive market data and prior year company performance in establishing target levels. Any equity grants awarded in proximity to an earnings announcement or other market event are coincidental in nature.

Restricted stock units and performance shares are discussed in further detail under Grants of Plan-Based Awards below following the Grants of Plan-Based Awards table.

Other Equity Awards

FirstEnergy has a restricted stock program, which is utilized solely for recruitment, retention and special recognition purposes. Award sizes, grant dates and vesting periods vary to allow flexibility. As a result of superior FirstEnergy performance, outstanding individual performance since assuming the role of CEO in January 2004 and the FirstEnergy Board of Directors strong desire to retain Mr. Alexander in his current capacity, the Compensation Committee recommended, and the FirstEnergy Board of Directors approved, a grant to Mr. Alexander of 98,271 shares of restricted stock on February 27, 2006. The shares will vest on April 30, 2013; however, the FirstEnergy Board of Directors has the ability to accelerate the vesting to April 30, 2011, or thereafter, at their discretion based on appropriate succession planning or other rationale they then believe to be appropriate. The Compensation Committee has the authority to modify all or select stock grants; however, the Compensation Committee has not taken such action since 2002.

Payment of restricted stock upon termination from FirstEnergy is discussed under Post-Termination Compensation and Benefits below. All equity awards granted to the named executive officers are subject to the share ownership guidelines discussed under Stock Ownership/Retention Guidelines below.

Restricted stock grants are discussed in further detail under Grants of Plan-Based Awards below following the Grants of Plan-Based Awards table.

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Retirement

The FirstEnergy Supplemental Executive Retirement Plan, or SERP, is limited to certain key executives. Mr. Morgan, Mr. Marsh, Mr. Alexander and Ms. Vespoli are participants in the SERP. Mr. Grigg does not participate in the SERP. The SERP is part of the integrated compensation program intended to attract, motivate and retain top executives who are in positions to make significant contributions to FirstEnergy s operation and profitability for the benefit of its customers and shareholders. The SERP benefit is equal to the greater of (i) 65% of the executive s highest annual salary, or (ii) 55% of the average of the executive s highest three consecutive years of salary plus annual incentive awards. The SERP benefit is reduced by the executive s pensions under tax-qualified pension plans of FirstEnergy or other employers, any supplemental pension under the FirstEnergy Executive Deferred Compensation Plan, or EDCP, and Social Security benefits. In some cases, an executive s tax-qualified pension and supplemental pension may exceed the SERP benefit, which eliminates any benefit payments under the SERP. This is not the case for the named executive officers reported in this prospectus as of December 31, 2006. The SERP also provides for disability and surviving spouse benefits. At the end of 2006, only 14 active employees were eligible participants for a SERP benefit upon retirement, and no new participants have been provided eligibility since 2001. The Compensation Committee must approve any new participants.

Earnings on Deferred Compensation

The EDCP offers executives the opportunity to accumulate assets on a tax-favored basis and acquire additional FirstEnergy stock. The EDCP is part of an integrated executive compensation program to attract, retain and motivate key executives who are in positions to make significant contributions to FirstEnergy s operation and profitability.

Above-market interest earnings on executives deferred compensation cash accounts are provided as an incentive for executives to defer base salary and short-term incentive awards. Additionally, a 20% FirstEnergy matching contribution on deferrals from short-term and long-term incentive awards directed to investment in FirstEnergy stock further ties management investment performance to FirstEnergy s success. FirstEnergy has determined that the levels of executive benefits in the aggregate are competitive and aligned with FirstEnergy s philosophy.

Personal Benefits and Perquisites

Executives may be eligible to receive limited perquisites offered by FirstEnergy, including financial planning and tax preparation services, country club dues and personal use of the corporate aircraft. FirstEnergy believes that financial planning by experts reduces the time that executives spend on that topic and assists in making the most of the financial rewards received from FirstEnergy. Some executives belong to a golf or country club so that they have an appropriate entertainment forum for customers and appropriate interaction with their communities. Pursuant to the direction of the FirstEnergy Board of Directors, Mr. Alexander is required to use FirstEnergy s corporate aircraft for all personal and business travel. Other executives, including the named executive officers, may from time to time, with CEO approval, use FirstEnergy s corporate aircraft for personal travel. FirstEnergy has a written policy that sets forth guidelines regarding the personal use of the corporate aircraft by executive officers and other employees. The Compensation Committee believes these perquisites are reasonable, competitive and consistent with the overall compensation philosophy.

Stock Ownership/Retention Guidelines

FirstEnergy believes it is critical that the interests of executives and shareholders be clearly aligned. As such, share ownership requirements, defined as a multiple of salary, are in place for FirstEnergy s executives as follows:

President and CEO 5 times salary

Executive Vice President and COO 4 times salary

Senior Vice Presidents and the equivalent 3 times salary

Vice Presidents and the equivalent 1 to 2 times salary

For 2006, the following were included to determine ownership status:

Shares directly or jointly owned in certificate form or in a stock investment plan,

Shares owned through the FirstEnergy Savings Plan, or Savings Plan,

Brokerage shares,

Shares held in the EDCP, and

Shares granted through the LTIP (restricted stock units and performance shares).

Once guidelines are attained, executives subject to the guidelines may exercise any or all vested stock options; however, they may sell only 50% of the shares granted by FirstEnergy after January 1, 2005. Additionally, FirstEnergy s Insider Trading Policy prohibits executive officers from hedging their economic exposure to the FirstEnergy stock that they own.

The guidelines are reviewed for competitiveness on an annual basis and were last reviewed at the February 2007 Compensation Committee meeting. The named executive officers listed have met the share ownership guidelines. As of March 1, 2007, Mr. Morgan owned 29,494 shares of FirstEnergy s stock, which more than satisfies his requisite stock ownership requirements.

Post-Termination Compensation and Benefits

The following table sets forth the payment of post-termination compensation and benefits under different scenarios for all named executive officers. Additional information regarding change in control agreements and provisions follows the table.

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2006 Post-Termination Compensation and Benefits

	Retirement(1)	Severance (Absent a change in control)	Change In Control	Voluntary Termination (pre-retirement eligible)(1)	Death(1)	Disability(1)
Base Salary	Accrued though date of retirement.	Accrued through date of severance.	Accrued through date of change-in-control termination.	Accrued through date of termination.	Accrued through date of qualifying event.	Accrued through date of qualifying event.
Severance Pay	N/A	3 weeks of pay for every one year of service, including the current year, calculated using base salary at the time of severance.	2.99 times the sum of base salary plus average incentive award over the past three years.(2)	N/A	N/A	N/A
Accrued and Banked Vacation	Paid in a lump sum.	Paid in a lump sum.	Paid in a lump sum.	Paid in a lump sum.	Paid in a lump sum.	Paid in a lump sum.
Health and Wellness Benefits	Retiree/spouse health and wellness provided.	Provided for the severance period.(3)	Provided for the severance period.(3)	Forfeited.	Survivor health and wellness provided as eligible.	Health and wellness provided as eligible.
STIP Award	Issued a prorated award based on full months of service.	Issued a prorated award based on full months of service.	Issue a prorated award based on full months of service.	Forfeited.	Issued a prorated award based on full months of service.	Issued a prorated award based on full months of service.
Performance Adjusted Restricted Stock Units(5)	Issued a prorated award, and all dividends earned, must have a minimum of 12 months in a cycle.	Issued a prorated award, and all dividends earned, must have a minimum of 12 months in a cycle.	For 2005 grants issued, 100% of shares and all dividends earned. For 2006 grants, payout based on share value protection rights.	Forfeited.	Issued 100% of shares and all dividends earned.	Issued 100% of shares and all dividends earned.
Discretionary Restricted Stock Units(5)	Issued a prorated award, and all dividends earned, must have a minimum of 36 months in a cycle.	Issued a prorated award, and all dividends earned, must have a minimum of 36 months in a cycle.	For 2005 grants issued, 100% of shares and all dividends earned. For 2006 grants payout based on share value protection rights.	Forfeited.	Issued 100% of shares and all dividends earned.	Issued 100% of shares and all dividends earned.

	Retirement(1)	Severance (Absent a change in control)	Change In Control	Voluntary Termination (pre-retirement eligible)(1)	Death(1)	Disability(1)
Performance Shares(5)	Issued a prorated award, must have a minimum of 12 months in a cycle.	Issued a prorated award, must have a minimum of 12 months in a cycle.	For 2004 and 2005 grants, issued prorated award of shares and dividends earned. For 2006 grants, payout based on change in control value protection rights.	Forfeited.	Issued a prorated award, must have a minimum of 12 months in a cycle.	Issued a prorated award, must have a minimum of 12 months in a cycle.
Stock Options(6)	All options vest as scheduled and must be exercised prior to the expiration date.	All vested options must be exercised within 90 days or the date of expiration, whichever is earliest. All unvested options are forfeited.	All options become immediately exercisable and must be exercised prior to the expiration date.	All vested options must be exercised within 90 days or the date of expiration, whichever is earliest. All unvested options are forfeited.	All options become immediately exercisable and must be exercised within one year of date of death.	All options become immediately exercisable and must be exercised prior to the expiration date.
Restricted Stock	Forfeited, if unvested.	Forfeited.	Issued 100% of shares and all dividends earned.	Forfeited.	Issued 100% of shares and all dividends earned.	Issued 100% of shares and all dividends earned.
Qualified Retirement Plan	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable to survivor in a monthly benefit.	Payable in a monthly benefit at earliest retirement age.
Nonqualified Retirement Plan	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable to survivor in a monthly benefit.	Payable in a monthly benefit at earliest retirement age.
SERP(7)	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Payable in a monthly benefit at earliest retirement age.	Forfeited if voluntarily terminated prior to retirement age.	Payable to survivor in a monthly benefit.	Payable in a monthly benefit at earliest retirement age.
Vested Executive Deferred Compensation	Payable as elected.	Payable as elected.	Payable as elected.	Payable as elected.	Payable to survivor as elected.	Payable as elected.

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	Retirement(1)	Severance (Absent a change in control)	Change In Control	Voluntary Termination (pre-retirement eligible)(1)	Death(1)	Disability(1)
Non-vested Executive Deferred Compensation	Payable as elected.(8)	Payable as elected.	Payable as elected.	Forfeited.	Payable to survivor as elected.	Payable as elected.
Additional Age and Service for Pension, EDCP and Benefits	N/A	N/A	Three years if covered by a Special Severance Agreement.	N/A	N/A	N/A
Reimburse IRC Section 280G	No.	No.	Yes, if covered by a Special Severance Agreement.	No.	No.	No.

(1) Benefits provided in these scenarios are also provided to all FirstEnergy s employees, if applicable.

(2) FirstEnergy has in place separate Special Severance Agreements with Mr. Marsh, Mr. Alexander, Mr. Grigg and Ms. Vespoli. Benefit shown would be provided to Mr. Marsh, Mr. Alexander and Ms. Vespoli. Mr. Grigg would be provided a cash payment of 2.99 times the sum of the base salary plus the target amount of the annual incentive award whether or not actually paid. Mr. Morgan would be provided severance pay benefits as described in the severance column in the event of a discharge without cause after a change in control.

(3) Active employee health and wellness benefits are provided to the named executive officers for the severance period, which is equal to three weeks for every year of service, including the current year (52-week minimum). At the end of the severance period, retiree health and wellness benefits are provided if retirement eligible.

(4) Mr. Morgan, Mr. Marsh and Mr. Alexander are eligible for retirement and would receive retiree health and wellness benefits in the event of a change in control. Mr. Grigg is eligible for retiree health care based upon the terms of his employment agreement. Ms. Vespoli would be provided health and welfare benefits as provided in the event of a severance.

(5) Beginning in 2007, payout of restricted stock units and performance shares will not occur until the completion of the performance cycle or the end of the vesting period.

(6) FirstEnergy has not granted any stock options under the LTIP since 2004 when the use of restricted stock units replaced stock options.

(7) The SERP benefit is limited to certain key executives. Mr. Alexander, Mr. Marsh, Mr. Morgan and Ms. Vespoli are eligible for a SERP benefit.

(8) If an executive voluntarily leaves FirstEnergy prior to age 60 (early retirement), any non-vested premium is forfeited.

Change In Control

Change in Control Special Severance Agreements, or Special Severance Agreements, are intended to ensure that certain executives are free from personal distractions in the context of a potential change in control when FirstEnergy s Board of Directors needs the objective assessment and advice of these executives to determine whether an offer is in the best interests of FirstEnergy and its shareholders. FirstEnergy has in place separate Special Severance Agreements with Anthony J. Alexander, Richard R. Grigg, Richard H. Marsh and Leila L. Vespoli. In each case, the agreements provide for the payment of severance benefits if the individual s employment with FirstEnergy or its subsidiaries is terminated under specified circumstances within three years after a change in control of FirstEnergy. Additionally, Mr. Alexander is eligible for the specified severance benefits if he resigns, for any reason, during a 90-day window period commencing 18 months following a change in control.

Circumstances defining a change in control are explained under Potential Post-Employment Payments below.

FirstEnergy executed agreements consistent with competitive practice with Mr. Marsh and Ms. Vespoli on December 31, 2003, with Mr. Alexander on March 5, 2004 and with Mr. Grigg on March 7, 2005. The Special Severance Agreements have initial three-year terms. FirstEnergy s Board of Directors reviews the Special

Severance Agreements annually at a regular meeting held between October 1 and December 31 of each year. FirstEnergy s Board of Directors decides at this meeting whether or not to extend the terms of the Special Severance Agreements for an additional year. In the 2006 review, all of the Special Severance Agreements were extended for an additional year.

The severance benefits provided reflect the fact that it may be difficult for employees to find comparable employment within a short period of time. In September 2006, as is the annual practice, the compensation consultant reviewed the current Special Severance Agreements in light of competitive practice and market trends. The consultant s findings indicate FirstEnergy s Special Severance Agreements are consistent with competitive practices, including the definition of change in control, eligibility for change in control agreements, levels of cash severance provided and the types of benefits covered. Under each of the above Special Severance Agreements, the executives would be prohibited from working for or with competing entities after receiving severance benefits pursuant to the Special Severance Agreement for two years. Additional details are provided in the 2006 Post-Termination Compensation and Benefits table provided above. A detailed representation of the termination benefits provided under a change in control scenario as of December 31, 2006, is provided below in the Potential Post-Employment Payments tables appearing later in this prospectus.

Employment Agreements

Mr. Grigg has an employment agreement in effect with FirstEnergy setting forth the general terms and conditions of his employment as COO dated July 20, 2004. The effective date is August 20, 2004. The original expiration date was August 20, 2007. In reviewing the agreement and Mr. Grigg s contributions, the FirstEnergy Board of Directors determined that FirstEnergy would benefit from Mr. Grigg remaining in the COO position for an additional period of time. As such, in January 2007, the agreement was amended and extended until March 31, 2008.

Impact of Regulatory Requirements on Compensation

The Compensation Committee is responsible for addressing pay issues associated with Section 162(m) of the Internal Revenue Code of 1986, as amended, or Code. Section 162(m) of the Code limits to $1 million FirstEnergy s tax deduction for certain compensation paid to FirstEnergy s most highly compensated executive officers. FirstEnergy, through the Compensation Committee, intends to attempt to qualify executive compensation as tax deductible to the extent feasible and where it believes it is in the best interests of FirstEnergy and its shareholders. FirstEnergy does not intend to permit this tax provision to distort the effective development and execution of FirstEnergy s compensation program. Thus, the Compensation Committee is permitted to and will continue to exercise discretion in those instances where satisfaction of tax law requirements could compromise the interests of FirstEnergy s shareholders. In addition, because of the uncertainties associated with the application and interpretation of Section 162(m) of the Code and the regulations issued thereunder, there can be no assurance that compensation intended to satisfy the requirements for deductibility under Section 162(m) of the Code will in fact be deductible.

FirstEnergy s compensation vehicles are primarily performance based awards that are not subject to the $1 million deduction limitation. However, base salary in excess of $1 million is subject to the deduction limitation. The STIP and the performance share component of the LTIP qualify as performance based compensation and are not subject to the $1 million deduction limit. A portion of the restricted stock unit component also qualifies as performance based compensation. Therefore, base salary in excess of $1 million and a portion of the restricted stock units are subject to the $1 million deduction limit. For 2006, Mr. Alexander s base salary was $1,216,923. After accounting for deferred base salary, there was no lost deductibility under Section 162(m) of the Code. No restricted stock units vested in 2006, and therefore, no lost deductibility under Section 162(m) of the Code.

Conclusion

The foundation of FirstEnergy s compensation philosophy is the concept of pay-for-performance. FirstEnergy provides a competitive total compensation program designed to attract, retain and reward employees whose performances drive company success. As a result, the executive compensation programs are designed to reward and retain executives who are responsible for leading the organization in achieving FirstEnergy s business objectives in the highly complex utility industry.

In evaluating each element of compensation (individually and in the aggregate), FirstEnergy has deemed total compensation provided to its executives reasonable, competitive and not excessive. Each element of direct compensation is linked to a performance measure that impacts either financial or operational performance. These performance measures drive profitability, safety and productivity, which have a positive impact on FirstEnergy as well as providing for an increased return on investment for shareholders.

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Summary Compensation Table

As of December 31, 2006

Name and Principal Position(1)	Year	Salary ($)	Bonus ($)	Stock Awards(2) ($)	Option Awards(3) ($)	Non-Equity Incentive Plan Compensation(4) ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(5) ($)	All Other Compensation(6) ($)	Total ($)
Anthony J. Alexander President and CEO of FirstEnergy	2006	$ 1,216,923	$ 0	$ 5,420,735	$ 581,763	$ 2,000,000	$ 3,468,246	$ 65,659	$ 12,753,326
Richard R. Grigg Executive Vice President and COO of FirstEnergy	2006	$ 749,154	$ 0	$ 1,209,784	$ 84,560	$ 874,086	$ 200,143	$ 73,986	$ 3,191,713
Richard H. Marsh Senior Vice President of FirstEnergy and Chief Financial Officer of FirstEnergy and JCP&L	2006	$ 461,865	$ 0	$ 842,871	$ 123,805	$ 514,003	$ 491,772	$ 25,139	$ 2,459,455
Stephen E. Morgan President of JCP&L	2006	$ 345,000	$ 0	$ 470,546	$ 51,718	$ 184,359	$ 254,342	$ 20,045	$ 1,326,009
Leila L. Vespoli Senior Vice President and General Counsel of FirstEnergy and JCP&L	2006	$ 457,769	$ 0	$ 1,052,221	$ 76,245	$ 435,414	$ 298,716	$ 21,437	$ 2,341,802

(1) In 2006, Mr. Morgan served as our President, Mr. Marsh served as our Chief Financial Officer and Ms. Vespoli served as our Senior Vice President and General Counsel. Mr. Alexander and Mr. Grigg were employees of FirstEnergy in 2006.

(2) Amounts shown in the Stock Awards column include amounts from awards granted in and prior to 2006 before forfeitures and reflect the dollar amount of compensation cost recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006, in accordance with the Statement of Financial Accounting Standards No. 123R, or SFAS 123R, of awards pursuant to the Incentive Plan. Compensation costs under SFAS 123R are recognized for financial reporting purposes over the period in which the employee is required to provide service in exchange for the award (typically the vesting period). Assumptions used in the calculation of these amounts are included in footnote 4 to FirstEnergy s audited financial statements for the fiscal year ended December 31, 2006, included in FirstEnergy s Annual Report on Form 10-K filed with the SEC on February 28, 2007.

For restricted common stock, the amounts recognized in 2006 are as follows: Alexander: $818,932; Grigg: $169,970; Marsh: $1,515; Morgan: $103,600; and Vespoli: $314,305. These amounts represent awards granted in and prior to 2006. These awards are not payable to the executive until the vesting date or other qualifying event shown in the 2006 Post-Termination Compensation and Benefits table above. Mr. Alexander s grant issued in 2006 is described under Other Equity Awards above.

For restricted stock units, the amounts recognized in 2006 are as follows: Alexander $1,375,748; Grigg $459,945; Marsh $203,106; Morgan $74,368; and Vespoli $154,147. These amounts represent awards granted in 2005 and 2006. These awards are not payable to the executive until the vesting date or other qualifying event shown in the 2006 Post-Termination Compensation and Benefits table above. The actual 2006 grants are described under Long-Term Incentive Program above.

For performance shares, the amounts recognized in 2006 are as follows: Alexander $3,226,055; Grigg $579,869; Marsh $591,337; Morgan $280,905; and Vespoli $576,107. These amounts represent awards granted in 2004, 2005 and 2006. These awards are not payable to the executive until the conclusion of the performance cycle or other qualifying event shown in the 2006 Post-Termination Compensation and Benefits table above. The actual 2006 grants are described under Long-Term Incentive Program above.

For matching contributions to the EDCP, the amounts recognized in 2006 are as follows: Marsh $46,913; Morgan $11,673; and Vespoli $7,662. These amounts represent the compensation cost associated with matching contributions made from 2003 to 2006.

(3) FirstEnergy has not issued stock option awards since 2004. Amounts shown in the Option Awards column include amounts from awards granted in and prior to 2004 and reflect the dollar amount of compensation cost recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006, in accordance with SFAS 123R of awards pursuant to the LTIP. Compensation costs under SFAS 123R are recognized for financial reporting purposes over the period in which the employee is required to provide service in exchange for the award (typically the vesting period). Assumptions used in the calculation of this amount are included in footnote 4 to FirstEnergy s audited financial statements for the fiscal year ended December 31, 2006, included in FirstEnergy s Annual Report on Form 10-K filed with the SEC on February 28, 2007.

(4) The Non-Equity Incentive Plan Compensation column is comprised of the STIP award earned in 2006.

(5) The Change in Pension Value and Nonqualified Deferred Compensation Earnings column reflects the aggregate increase in actuarial value to the executive officer of all defined benefit and actuarial plans (including supplemental plans) accrued during the year and above-market earnings on nonqualified deferred compensation. The change in values for the pension plans are as follows: Alexander $3,428,532; Grigg $200,143; Marsh $436,877; Morgan $236,092; and Vespoli $268,158. The compensation changes related to Mr. Alexander s promotion in 2004 from COO to CEO significantly increased his pension benefits which affected the change in present value shown above. The above-market earnings on compensation that are deferred on a basis that is not tax-qualified are also included in this column. The formula used to determine the above market earnings equals (2006 total interest x {difference in the 1999 Applicable Federal Rate for long-term rates, or AFR, and the plan rate}) divided by the plan rate. The above market earnings on nonqualified deferred compensation for the named executive officers are: Alexander $39,714; Marsh $54,895; Morgan $18,250; and Vespoli $30,558.

(6) The All Other Compensation column includes compensation not required to be included in any other column. This includes matching FirstEnergy common stock contributions under the tax-qualified Savings Plan: Alexander $11,220; Grigg $7,259; Marsh $8,969; Morgan $11,220; and Vespoli $11,220.

In addition, certain executives are eligible to receive limited perquisites offered by FirstEnergy. In 2006, the named executives were provided: (1) financial planning and tax preparation services for Mr. Marsh, Mr. Alexander and Ms. Vespoli; (2) country club dues for Mr. Alexander, Mr. Grigg, Mr. Marsh, Mr. Morgan and Ms. Vespoli; (3) entertainment expenses during the FirstEnergy Board of Directors meeting for Mr. Alexander and Mr. Grigg; (4) the dollar value of Executive Supplemental Life Insurance for Mr. Alexander, Mr. Marsh and Ms. Vespoli; (5) holiday gifts for Mr. Marsh, Mr. Alexander, Mr. Grigg and Ms. Vespoli; and (6) personal use of the corporate aircraft for Mr. Alexander and Mr. Grigg. Of the total All Other Compensation amounts for Mr. Grigg, $63,520 was for use of the corporate aircraft. The FirstEnergy Board of Directors requires Mr. Alexander to use corporate aircraft for all travel for security reasons. The value of the use of corporate aircraft is calculated based on the aggregate variable operating costs to FirstEnergy, including fuel costs, trip-related maintenance, universal weather-monitoring costs, on-board catering, landing/ramp fees and other miscellaneous variable costs. Fixed costs, which do not change based on usage, such as pilots salaries, the amortized costs of FirstEnergy aircraft and the cost of maintenance not related to trips are excluded. Amounts for personal use of aircraft are included in the table. Executive officers spouses and immediate family members may accompany executives on FirstEnergy aircraft using unoccupied space on flights that were already scheduled, and FirstEnergy incurs no aggregate incremental cost in connection with such use. The amounts reported utilize a different valuation methodology than used for income tax purposes, where the cost of the personal use of FirstEnergy aircraft has been calculated using the Standard Industrial Fare Level tables found in the tax regulations. All other perquisites are valued at the invoice cost charged to FirstEnergy.

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Grants of Plan-Based Awards

As of December 31, 2006

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards(2)			All Other Stock Awards: Number of Shares of Stock or Units(2) (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards(3)
		Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)				
Anthony J. Alexander		$ 617,500	$ 1,235,000	$ 2,346,500							
	2/27/2006(8)							100,645			$ 5,130,882
	3/1/2006(4)				36,328	48,437	60,547				$ 3,083,053
	4/1/2006(6)					32,904	49,356				$ 2,413,508
Richard R. Grigg		$ 285,000	$ 570,000	$ 1,026,000							
	3/1/2006(4)				11,465	15,286	19,108				$ 972,979
	4/1/2006(6)					9,719	14,579				$ 712,913
Richard H. Marsh		$ 152,750	$ 305,500	$ 565,175							
	3/1/2006(4)				4,608	6,144	7,680				$ 391,066
	3/1/2006(5)							605			$ 29,951
	3/1/2006(7)							5,028			$ 256,026
	4/1/2006(6)					5,009	7,514				$ 367,435
Stephen E. Morgan		$ 77,625	$ 155,250	$ 271,688							
	3/1/2006(4)				1,822	2,429	3,037				$ 154,644
	4/1/2006(6)					2,206	3,309				$ 161,810
Lela L. Vespoli		$ 139,500	$ 279,000	$ 488,250							
	3/1/2006(4)				3,858	5,144	6,430				$ 327,416
	4/1/2006(6)					4,956	7,434				$ 363,523

(1) Reflects the possible payout range of the STIP. Actual awards earned in 2006 and paid March 1, 2007 are reported in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table above.

(2) Includes dividend equivalent units and dividends earned on grants of restricted stock units, the 20% matching contribution, performance shares and restricted stock.

(3) Fair market value calculation for each grant is explained under Grants of Plan-Based Awards below. In cases where equity grants have performance factors, the highest number of shares that could be issued was used in the calculation.

(4) Performance-adjusted restricted stock unit grant described under Long-Term Incentive Program above and under Grants of Plan-Based Awards below.

(5) Represents 20% matching contribution applied to funds deferred into the EDCP stock account described under Long-Term Incentive Program above and under Nonqualified Deferred Compensation below.

(6) Performance share grant described under Long-Term Incentive Program above and under Grants of Plan-Based Awards below.

(7) Discretionary restricted stock unit grant described under Long-Term Incentive Program above and under Grants of Plan-Based Awards below.

(8) Restricted stock grant described under Long-Term Incentive Program above and under Grants of Plan-Based Awards below.

Grants of Plan-Based Awards

The STIP provides awards to executives whose contributions support the achievement of corporate financial and operational goals. In 2006, target award opportunities for the named executive officers ranged from 45% of salary to 100% of salary. Awards for the short-term incentive portion based on operational performance range from 50% of target for performance at the threshold level to 150% of target for outstanding performance. Awards for the short-term incentive portion based on financial performance range from 50% of target for performance at threshold to a maximum of 200% of target for outstanding performance. Awards are not made if threshold performance is not achieved. Awards are mathematically interpolated for performance between threshold and maximum, and no positive or negative discretion is applied to the final awards. The Compensation Committee has no authority to adjust upwards the amount payable to a covered employee with respect to a particular award.

Long-term incentive awards are awarded under the terms of the Incentive Plan. In 2006, FirstEnergy delivered long-term incentives through a combination of restricted stock units and performance shares. FirstEnergy has not issued stock options under its LTIP since 2004.

The process for allocating awards is similar for all executives. The target levels are established in February, and performance is measured throughout the cycle. In 2006, performance-adjusted restricted stock unit target award opportunities for the named executive officers ranged from 35% of salary to 195% of salary. In 2006, performance share target award opportunities for the named executive officers ranged from 30% of salary to 125% of salary.

Performance-adjusted restricted stock units are granted to all eligible executives. A restricted stock unit is equivalent to one share of FirstEnergy common stock and does not carry voting rights. Based on competitive analysis, each eligible executive received an initial grant of performance-adjusted restricted stock units, at a target level based on the executive s annual salary as of March 1, 2006, and calculated using the average of the high and low stock price on March 1, 2006 ($50.92). These performance-adjusted restricted stock units were granted to each executive with the right to receive, at the end of the three-year restriction period, shares of FirstEnergy common stock.

The actual number of shares issued may be adjusted upward or downward by 25% based on FirstEnergy s performance against the three key metrics described under Long-Term Incentive Program above. The actual performance result for each of the three years during the restriction period will be averaged and compared to the average of the target level set for each performance metric as determined by the Compensation Committee. During the three-year cycle, dividend equivalents accrue on the performance-adjusted restricted stock units at the same rate paid to shareholders and convert to additional units at the end of each quarter during the restriction period. Once restrictions lapse, if applicable, the performance factor multiplier is applied to the original grant and all dividend equivalent units earned and the appropriate number of shares is purchased in the name of the executive.

Discretionary restricted stock units do not have a performance component. Dividend equivalents accrue on the discretionary restricted stock units at the same rate paid to shareholders and convert to additional units at the end of each quarter during the period of restriction. The period of restriction is five years. Once restrictions lapse, the appropriate number of shares are purchased in the name of the executive.

FirstEnergy s performance share program provides executives with the opportunity for awards based on FirstEnergy s total shareholder return over a three-year period relative to the EEI Index. The number of performance shares granted is calculated by multiplying the executive s March 1 salary by the eligible incentive percent and dividing by the average high and low common stock price during December of the previous year ($48.47).

Performance shares are not actual voting shares; rather, they are equivalent units, or phantom shares, which track the market performance of FirstEnergy s common stock. During the three-year cycle, performance shares earn dividend equivalent units, applied quarterly, at the same rate paid to shareholders. If the performance factors are met, the 2006-2008 performance share grant will payout in March 2009. If FirstEnergy s performance is below threshold (defined as the 40th percentile), no award is paid. If FirstEnergy s performance is at or above the 86th percentile, awards are paid at the maximum of 150% of target. Awards are interpolated for performance between these two points. Performance shares typically payout in cash at the end of the performance cycle.

FirstEnergy has a restricted stock program, which is utilized solely for recruitment, retention and special recognition purposes. Award sizes, grant dates and vesting periods vary to allow flexibility. Restricted stock differs from restricted stock units in that the appropriate number of shares are purchased on the open market ($50.98 for Mr. Alexander s 2006 grant), as soon as practicable, after the date the signed restricted stock grant agreement is received. The vesting terms and conditions of restricted stock grants vary. Executives receiving restricted stock grants have full voting rights during the period of restriction. During the restriction period, dividends are earned and applied quarterly, at the same rate as shareholders. Cash dividends are converted automatically into shares and are subject to the same restrictions as the original grant. The purpose and methods of granting restricted stock, in general, and detailed information regarding Mr. Alexander s 2006 grant is explained further under Other Equity Awards above and is reflected in the Summary Compensation Table above.

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Contributions of STIP and LTIP awards to the EDCP stock account are provided with a 20% matching contribution made by FirstEnergy. Dividend equivalents accrue on the 20% matching contribution and stock units held in the EDCP based on the same dividend rate paid to shareholders and convert to additional units at the end of each quarter.

The number of shares associated with the 20% matching contribution is calculated by dividing the calculated 20% dollar matching contribution by the average closing price of $49.47 for the month of February 2006.

Executives are generally responsible for paying all tax obligations regarding any grant(s) received. Grants are not grossed-up by FirstEnergy to cover tax obligations unless the award is accelerated under the terms of a Special Severance Agreement (Special Severance Agreements are discussed under Change in Control above). Taxes are paid in cash for performance shares but may be paid in cash or by withholding shares for restricted stock units or EDCP share payouts. Starting with the March 1, 2007, performance-adjusted and discretionary restricted stock unit grants, FirstEnergy will require payment of taxes by selling shares on the open market. No consideration, other than services rendered, is paid by an executive when receiving a grant.

The grant date fair value of stock and option awards values are calculated in accordance with SFAS 123R as follows:

Performance shares are treated as a liability, where the value is determined by multiplying the closing price of FirstEnergy common stock on the date of grant by the number of performance shares granted. The fair market value for the April 1, 2006 grant is $48.90 per share. Performance shares values are recalculated at each financial statement reporting date, through the date the award is settled in order to reflect the market fluctuations of FirstEnergy common stock.

Performance-adjusted and discretionary restricted stock units are treated as a fixed cost, where the value is determined by multiplying the average high and low price of FirstEnergy s common stock on the date of grant by the number of restricted stock units granted. The fair market value for the March 1, 2006 grant is $50.92 per share. Contrary to performance shares, the compensation cost associated with restricted stock units remains constant through the date the award is settled without regard to market fluctuations of FirstEnergy common stock.

The grant date fair market value for restricted stock is the purchase price plus commission paid for the restricted stock multiplied by the number of shares granted. The purpose and methods of granting restricted stock, in general, and detailed information regarding Mr. Alexander s 2006 grant is explained further under Other Equity Awards above and is reflected in the Summary Compensation Table above.

The shares in the EDCP are recorded as a liability. The fair market value is determined by multiplying the 20% matching contribution and all dividends earned up to December 31, 2006, by the average closing price of $49.47 for the month of February 2006.

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Outstanding Equity Awards

As of December 31, 2006

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable(1)	Number of Securities Underlying Unexercised Options (#) Unexercisable(2)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested(3)(4) (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(3)	Equity Incentive Plan Awards: Number of Unearned Shares, Units, or Other Rights That Have Not Vested(2) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested ($)(3)
Anthony J. Alexander	90,000		N/A	$ 34.45	4/1/2012	100,645	$ 6,073,908	63,532(5)	$ 3,834,156
	80,450		N/A	$ 29.71	3/1/2013			60,447(5)	$ 3,654,011
	192,825	64,275	N/A	$ 38.76	3/1/2014			42,026(6)	$ 2,536,266
								57,928(7)	$ 3,495,973
								49,356(8)	$ 2,978,664
Richard R. Grigg	27,379	27,380	N/A	$ 39.46	8/20/2014	13,702	$ 826,916	22,392(5)	$ 1,351,357
								19,108(5)	$ 1,153,168
								17,149(7)	$ 1,034,931
								14,579(8)	$ 879,851
Richard H. Marsh	17,500		N/A	$ 34.45	4/1/2012	5,028	$ 303,440	6,798(5)	$ 410,259
	23,750		N/A	$ 29.71	3/1/2013			7,680(5)	$ 463,488
	38,475	12,825	N/A	$ 38.76	3/1/2014			9,837(6)	$ 593,655
								8,676(7)	$ 523,626
								7,513(8)	$ 453,432
								568(10)	$ 34,288
								605(11)	$ 36,538
Stephen E. Morgan	4,000		N/A	$ 34.45	4/1/2012	7,956	$ 480,145	3,863(5)	$ 233,132
	7,800		N/A	$ 29.71	3/1/2013			3,307(5)	$ 183,283
	17,025	5,675	N/A	$ 38.76	3/1/2014			4,694(6)	$ 283,253
								4,226(7)	$ 255,009
								3,311(8)	$ 199,789
								182(9)	$ 10,984
Leila L. Vespoli	40,000		N/A	$ 29.50	5/16/2011	53,033	$ 3,200,557	7,478(5)	$ 451,297
	35,000		N/A	$ 34.45	4/1/2012			6,430(5)	$ 388,051
	45,000		N/A	$ 29.71	3/1/2013			9,363(6)	$ 565,046
	36,600	12,200	N/A	$ 38.76	3/1/2014			8,676(7)	$ 523,626
								7,433(8)	$ 448,609
								535(9)	$ 32,281

(1) Options vested March 1, 2007 but not vested December 31, 2006 are included in the Number of Securities Underlying Unexercised Options Exercisable column.

(2) Options with an exercise price of $38.76 vest on March 1, 2008.

(3) Includes dividends and dividend equivalent units earned through December 31, 2006. The market value is based on FirstEnergy common stock closing price $60.35 on December 29, 2006.

(4) Vesting dates for restricted stock or discretionary restricted stock units are as follows: Mr. Alexander s restricted stock grant vests on April 29, 2013; Mr. Grigg s restricted stock grant vests August 20, 2007; Mr. Marsh s discretionary restricted stock units vest on March 1, 2011; Mr. Morgan s restricted stock grant vests on March 1, 2008; and Ms. Vespoli s restricted stock unit grant vests 50% on March 1, 2010 and 50% on March 1, 2015. The market value is based on FirstEnergy common stock closing price $60.35 on December 29, 2006.

(5) Performance-adjusted restricted stock units were granted March 1, 2005 and March 1, 2006, respectively. The March 1, 2005 grant will pay out on March 1, 2008 based on FirstEnergy s performance from 2005-2007, and the March 1, 2006 grant will pay out on March 1, 2009 based on FirstEnergy s performance from 2006-2008. The projected payout values are shown at the maximum payout value of 125%.

(6) Performance shares granted in 2004 for the 2004-2006 performance cycle which vested December 31, 2006. The performance measures for this grant were achieved and paid out at the maximum level (150%) on March 1, 2007.

(7) Performance shares granted in 2005 for the 2005-2007 performance cycle which vest December 31, 2007 shown at the estimated maximum payout value of 150%.

(8) Performance shares granted in 2006 for the 2006-2008 performance cycle which vest December 31, 2008 shown at the estimated maximum payout value of 150%.

(9) Represents 20% matching contribution on funds deferred into the EDCP stock account in 2004, which vested on March 1, 2007.

(10) Represents 20% matching contribution on funds deferred into the EDCP stock account in 2005, which vests on March 1, 2008.

(11) Represents 20% matching contribution on funds deferred into the EDCP stock account in 2006, which vests on March 1, 2009.

Option Exercises and Stock Vested

As of December 31, 2006

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized Upon Exercise ($)	Number of Shares Acquired on Vesting(1) (#)	Value Realized on Vesting ($)
Anthony J. Alexander		$ 0	8,743(3)	$ 434,090
			28,017(4)	$ 1,690,844
Richard R. Grigg		$ 0		$ 0
Richard H. Marsh(2)	20,625	$ 359,063	1,167(3)	$ 57,942
			6,558(4)	$ 395,770
			3,027(5)	$ 149,756
Stephen E. Morgan		$ 0	3,129(4)	$ 188,835
Leila L. Vespoli		$ 0	3,500(3)	$ 173,775
			6,242(4)	$ 376,697
			531(6)	$ 27,279

(1) Includes dividends earned through December 31, 2006.

(2) In accordance with established 10b5-1 plans, effective April 1, 2004, Mr. Marsh exercised options on April 3, 2006.

(3) Restricted stock grant vested on February 20, 2006.

(4) Performance shares for the 2004-2006 performance cycle vested on December 31, 2006 and paid out in cash on March 1, 2007. The dollar amount reflects the fair market value of $60.35 on the date of vesting and the maximum payout value of 150%. The performance shares were paid as follows: Mr. Alexander

received $2,536,266, of which $1,000,000 was deferred into the EDCP stock account, and $536,266 was converted into shares and will be paid out March 21, 2007; Mr. Marsh received $593,655, of which $558,036 was deferred into the EDCP stock account; Mr. Morgan received $283,238, of which was deferred into the EDCP stock account; and Ms. Vespoli received $565,045, of which $282,522 was deferred into the EDCP stock account.

(5) Represents funds deferred in 2006 to the EDCP stock account described under Nonqualified Deferred Compensation above. These funds are converted to shares based on the closing stock price on March 1, 2006 ($49.47) and are fully vested. The 20% matching contribution applied to the deferral is not included, as these shares are not vested for three years.

(6) Represents the 20% matching contribution deferred in 2004 and vested in 2006, which was further deferred by Ms. Vespoli in 2006 to the retirement stock account described under Nonqualified Deferred Compensation above. For purposes of this table, the fair market value of the 20% matching contribution and all dividends earned during the three year vesting period are valued based on the closing stock price on March 1, 2006 ($51.00).

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Pension Benefits As of December 31, 2007

Name	Plan Name	Number Years Credited Service (#)	Present Value of Accumulated Benefit(1) ($)	Payments During Last Fiscal Year ($)
Anthony J. Alexander	Qualified Plan	34	$ 1,000,083	$ 0
	Nonqualified (Supplemental) Plan		$ 7,771,302	$ 0
	SERP		$ 1,072,089	$ 0
	Total		$ 9,783,474	
Richard R. Grigg	Qualified Plan	2	$ 93,003	$ 0
	Nonqualified (Supplemental) Plan		$ 252,119	$ 0
	SERP		$ 0	$ 0
	Total		$ 345,122	
Richard H. Marsh	Qualified Plan	26	$ 835,249	$ 0
	Nonqualified (Supplemental) Plan		$ 1,599,588	$ 0
	SERP		$ 380,082	$ 0
	Total		$ 2,814,919	
Stephen E. Morgan	Qualified Plan	29	$ 907,559	$ 0
	Nonqualified (Supplemental) Plan		$ 907,559	$ 0
	SERP		$ 237,765	$ 0
	Total		$ 2,052,883	
Leila L. Vespoli	Qualified Plan	22	$ 471,167	$ 0
	Nonqualified (Supplemental) Plan		$ 866,752	$ 0
	SERP		$ 346,132	$ 0
	Total		$ 1,684,051	

(1) The Present Value of Accumulated Benefit is determined as of December 29, 2006, using the following assumptions: discount rate of 6%, the RP-2000 Combined Healthy Life Mortality Table and retirement at the earliest unreduced retirement ages as defined later. The calculations for all pension benefits are based on current base and incentive compensation and do not consider salary increases.

Pension Benefits

Qualified and Nonqualified Plans

FirstEnergy offers a Qualified and Nonqualified Plan to all of the named executive officers. FirstEnergy pays the entire costs of these plans. Payments from the Qualified Plan are maximized considering base salary earnings and the applicable federal and plan limits. The Nonqualified Plan is designed to provide a comparable benefit to the executive without restrictions of federal and plan limits and as a method to provide a competitive retirement benefit. The pension benefit from the Qualified and Nonqualified Plans provided to the named executive officers is the greater benefit determined using the following two formulas:

(1) Career Earnings Benefit Formula: A fixed (2.125%) factor is applied to the executive s total career earnings to determine the accrued (age 65) career endings benefit. Career earnings generally include base salary, overtime pay, shift premiums, annual incentive awards and other similar compensation.

(2) Adjusted Highest Average Monthly Base Earnings Benefit Formula: The benefit is equal to the sum of A and B where A is the highest average monthly base earnings, or HAMBE, times the sum of:

1.58% times the first 20 years of benefit service;

1.18% times the next 10 years of benefit service;

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78% times the next 5 years of benefit service; and

1.10% times each year of benefit service in excess of 35 years

and B is an amount equal to 0.32% times number of years of service (up to 35 years) times the greater of the difference between the highest average monthly base earnings and the lesser of 150% of covered compensation or the Social Security Wage Base, and zero.

The HAMBE for the Qualified Plan are the highest 48 consecutive months of base earnings the executive had in the 120 months before retirement or other separation of employment. Base earnings are the employee s straight time rate of pay without overtime, deferred compensation, incentive compensation, other awards, or accrued or unused vacation paid at termination. The HAMBE for the Nonqualified Plan are the same as the Qualified Plan described above except that incentive and deferred compensation are included. Covered compensation is the average (without indexing) Social Security Taxable Wage Base in effect for each calendar year during the 35-year period that ends when the executive reaches the Social Security normal retirement age.

According to the FirstEnergy Pension Plan, or Pension Plan, which also covers our employees, normal retirement is at age 65, and the earliest retirement is at age 55 if the employee has at least ten years of credited service. Mr. Alexander, Mr. Marsh and Mr. Morgan, currently are eligible for a reduced pension benefit based on the Early Retirement Reduction Table below. Ms. Vespoli does not meet the age requirement, and Mr. Grigg does not meet the service requirement for early retirement. The earliest retirement age without reduction for the Qualified and Supplemental Plans is age 60 for Mr. Alexander, Mr. Marsh, Mr. Morgan and Ms. Vespoli and age 65 for Mr. Grigg based on the terms of his employment agreement.

Mr. Alexander, Mr. Grigg, Mr. Marsh and Ms. Vespoli also have Special Severance Agreements for change in control, which would credit them with three additional years of age and service for the purposes of the nonqualified benefit calculations.

Early Retirement Reduction Table

If payment begins at age	**The benefit is multiplied by**
60 and up	100%
59	88%
58	84%
57	80%
56	75%
55	70%

The accrued benefits vest upon the completion of 5 years of service. The benefits generally are payable in the case of a married executive in the form of a qualified spouse 50% joint and survivor annuity or in the case of an unmarried executive in the form of a single life annuity. There is also an option to receive the benefit as a joint and survivor annuity with or without a pop-up provision or a period certain annuity. A pop-up provision in an annuity provides a reduced monthly benefit, payable to the executive until death. Upon death, the executive s named beneficiary will receive 25%, 50%, 75% or 100 % of the executive s benefit based on the executive and the beneficiary s age and the percentage to be continued after the executive s death. However, if the beneficiary predeceases the executive, the monthly payment pops-up to the payment which would have been payable as a single life annuity.

Supplemental Executive Retirement Plan

In addition to the Qualified and Nonqualified Plans, Mr. Alexander, Mr. Marsh and Ms. Vespoli are also eligible to receive an additional nonqualified benefit from the SERP. The earliest retirement age without reduction for the SERP is age 65. Mr. Grigg, who was hired in 2004, is not a participant in the SERP. The SERP is also discussed under Elements of Compensation Retirement above.

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An executive participating in the SERP shall be eligible to receive a supplemental benefit after termination of employment due to retirement, death, disability or involuntary separation that directly is related to either the executive s: (a) average of the highest 12 consecutive full months of base salary earnings paid to the executive in the 120 consecutive full months prior to termination of employment, including any salary deferred in the EDCP or the Savings Plan, or (b) average of the highest 36 consecutive full months of base salary earnings and annual incentive awards paid to the executive in the 120 consecutive full months prior to termination of employment, including any salary and annual incentive awards deferred into the EDCP and Savings Plan.

A supplemental benefit under the SERP will be determined in accordance with and shall be non-forfeitable upon the date the executive terminates employment under the conditions described in the following sections:

Retirement Benefit

An executive retiring from FirstEnergy on or after age 55 who has completed 10 years of service will be entitled to receive, commencing at retirement, a monthly supplemental retirement benefit under the SERP equal to 65% of (a) above or 55% of (b) above, whichever is greater, multiplied by the number of months of service the executive has completed after having completed 10 years of service, up to a maximum of 60 months, divided by 60, less:

i) The monthly primary Social Security benefit to which the executive may be entitled at such retirement (or the projected age 62 benefit if retirement occurs prior to age 62), irrespective of whether the executive actually receives such benefit at the time of retirement, and

ii) The monthly early, normal or deferred retirement income benefit to which the executive may be entitled at such retirement under the Pension Plan, the monthly supplemental pension benefit under the EDCP and the monthly benefit, or actuarial equivalent, under the pension plans of previous employers, all calculated by an actuary selected by FirstEnergy, with the following assumptions based on the executive s marital status at the time of such retirement:

In the case of a married executive, in the form of a 50% joint and survivor annuity.

In the case of an unmarried executive, in the form of a single-life annuity.

For an executive who retires prior to attaining age 65, the net dollar amount above shall be further reduced by one-fourth of 1% for each month the commencement of benefits under the SERP precedes the month the executive attains age 65.

Death Benefit

If the executive dies, 50% of the executive s supplemental retirement benefit actuarially adjusted for the executive s and spouse s ages will be paid to the executive s surviving spouse. Payment will begin the month following death and continue for the remainder of the surviving spouse s life. For an executive who dies prior to attaining age 65, the benefit shall be reduced further by one-fourth of 1% for each month the commencement precedes the executive s age 65, with a maximum of 30%.

Disability Benefit

An executive terminating employment due to a disability may be entitled to receive, commencing at disability, a monthly supplemental retirement benefit under the SERP equal to 65% of (a) above or 55% of (b) above, whichever is greater, less disability benefits from:

Social Security;

the Pension Plan;

the long-term disability plan; and

other employers.

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The disability benefit continues until the executive attains age 65, retires from FirstEnergy, dies or is no longer disabled, whichever occurs first. Upon retirement, benefits are calculated as described under Retirement Benefit above. In the event of death, benefits are calculated as described under Death Benefit above.

Nonqualified Deferred Compensation

As of December 31, 2006

Name	Executive Contributions in Last Fiscal Year(1) ($)	Registrant Contributions in Last Fiscal Year(2) ($)	Aggregate Earnings in Last Fiscal Year(1)(3) ($)	Aggregated Withdrawals/ Distributions(4) ($)	Aggregate Balance at Last Fiscal Year End ($)
Anthony J. Alexander	$ 227,748	$ 0	$ 331,426	$ 0	$ 2,826,011
Richard R. Grigg	$ 0	$ 0	$ 0	$ 0	$ 0
Richard H. Marsh	$ 443,151	$ 29,247	$ 468,076	$ 0	$ 3,903,075
Stephen E. Morgan	$ 34,502	$ 0	$ 80,742	$ 0	$ 923,586
Leila L. Vespoli	$ 152,653	$ 0	$ 244,094	$ 0	$ 2,085,230

(1) Executive contributions include the deferral of base salary and STIP and LTIP program payments, as follows: Alexander all contributions from 2006 base salary; Grigg none; Marsh $155,789 from 2006 base salary, $141,127 from 2005 STIP deferred in 2006 and $146,235 from the 2003-2005 performance share cycle award deferred in 2006; Morgan all contributions from 2006 base salary; and Vespoli $91,774 from 2006 base salary and $60,879 from 2005 STIP deferred in 2006.

The executive contributions from 2006 base salary are also included in the Salary column of the 2006 Summary Compensation Table above. Deferrals of 2006 STIP and the 2004-2006 performance share cycle award deferred in 2007 are not included in the above Nonqualified Deferred Compensation table, but are as follows: Alexander $1,000,000 from 2006 STIP and $1,000,000 from the 2004-2006 performance share cycle award; Grigg none ; Marsh $483,163 from 2006 STIP and $558,036 from the 2004-2006 performance share cycle award; Morgan none; and Vespoli $87,083 from 2006 STIP and $282,523 from the 2004-2006 performance share cycle award.

(2) Registrant contributions include 20% FirstEnergy matching contributions on 2005 earned incentives, which were deferred in 2006 as follows: Alexander none; Grigg none; Marsh $29,247; Morgan none; and Vespoli none. Registrant contributions of the 20% FirstEnergy matching contributions on the 2006 earned incentives reported in the Stock Awards column of the 2006 Summary Compensation Table above and deferred in 2007 are not included in the above Nonqualified Deferred Compensation table but are as follows: Alexander $200,000; Grigg none; Marsh $111,607; Morgan none; and Vespoli $56,505.

(3) The compounded annual rate of return on cash accounts was 8.63%. The compounded annual rate of return on stock accounts was 27.2%, which includes both dividends and appreciation. The Aggregate Earnings and Aggregate Balance columns include above-market earnings, which have been reported in the Change in Pension Value and Nonqualified Deferred Compensation Earnings column of the current year Summary Compensation Table, as follows: Alexander $39,714; Grigg none; Marsh $54,895; Morgan $18,250; and Vespoli $30,558.

(4) At the time of deferral, participants may elect to receive distribution of stock accounts at the close of the three-year vesting period or at termination of employment. None of the named executive officers elected a distribution of the 2003 stock accounts which vested in 2006.

Nonqualified Deferred Compensation

The EDCP is a nonqualified defined contribution plan, which provides for the voluntary deferral of compensation. Participants may defer up to 50% of base salary, up to 100% of short-term incentive compensation and up to 100% of cash long-term incentive compensation. Participation in the EDCP is limited to FirstEnergy s management employees.

Two investment options are available under the EDCP. Participants may direct deferrals of base salary and short-term incentive compensation to an annual cash retirement account, which accrues interest. Participants may direct deferrals of short-term incentive compensation and long-term incentive compensation to an annual stock account.

Interest is credited to the retirement accounts. The interest rate changes annually and is based upon the Moody s Corporate Bond Index rate plus three percentage points.

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The stock accounts are tracked in stock units and accrue additional stock units based on the same dividend rate paid to shareholders. The stock accounts are valued at the fair market value of FirstEnergy s common stock. Contributions to the stock accounts are provided with a 20% matching contribution made by FirstEnergy. Stock units are earned on the 20% matching contribution based on the same dividend rate paid to shareholders. The number of shares associated with the 20% matching contribution is calculated by dividing the calculated 20% dollar matching contribution by the average closing price of $49.47 for the month of February 2006.

The participant s contribution and additional dividend units are vested immediately; FirstEnergy s 20% matching contributions and additional dividend units thereon vest at the end of a three-year period and are subject to forfeiture prior to the conclusion of that vesting period. These shares can be further deferred into a retirement stock account. A matching contribution is not applied to shares further deferred into the retirement stock account. Participants may elect to receive payments from the retirement accounts in any combination of lump sum payment and/or monthly installment payments for up to 25 years, provided that the account balance is at least $100,000. Differing distribution elections may be made for retirement, disability and pre-retirement death. In the event of involuntary severance prior to retirement eligibility, the account will be paid in a single lump sum payment or, for accounts grandfathered and not subject to Code Section 409A, in either a lump sum payment or in three annual installments at the participant s previously established election. Payments may not commence until termination of employment.

There is no in-service withdrawal option for retirement accounts which are subject to Code Section 409A. Amounts that were vested as of December 31, 2004 are available for an in-service withdrawal of the full grandfathered account subject to a 10% penalty.

Stock account distributions are limited to a lump sum payment in the form of FirstEnergy common stock at the end of the three-year company match vesting period or to a further deferral until termination. If further deferred until termination, the account will be converted to cash based upon the fair market value of the account at termination, and the balance will be rolled over to the corresponding annual cash retirement account for distribution in lump sum or monthly installments as elected under the cash retirement account.

The 20% matching contribution shares received by our named executive officers and all dividends earned through December 31, 2006 are reported on the Grants of Plan-Based Awards table under the All Other Stock Awards: Number of Shares of Stock or Units column.

Stock paid out on March 1, 2006 or further deferred into the retirement stock account in 2006 is valued at $51.00, the closing price on March 1, 2006. No named executive officer elected to receive a payout of their EDCP deferred stock account in 2006.

Potential Post-Employment Payments

The 2006 Post-Termination Compensation and Benefits table above describes the treatment of all elements of compensation in the event of a retirement/voluntary termination, severance (absent a change in control), change in control, death or disability. The amounts shown in the following tables do not include payments and benefits to the extent they are provided on a non-discriminatory basis to salaried employees generally upon termination of employment.

The post-termination calculations are based on the following assumptions:

- The amounts disclosed are estimates of the amounts which would be paid out to the executives upon their termination. The actual amounts paid can be determined only at the time of such executive s separation from FirstEnergy;

- December 29, 2006 is the date of termination;

- The STIP award is based on 2006 performance and payable March 1, 2007;

The LTIP award includes stock options, performance shares, performance-adjusted and discretionary restricted stock units and restricted stock;

The closing common stock price for the month of December 2006: $60.30; applied to value stock options, restricted stock units and restricted stock;

The average high/low common stock price for the month of December 2006: $60.81; applied to value performance shares (2005-2007 and 2006-2008 cycles);

The average high/low common stock price for December 29, 2006: $60.35; applied to value performance shares (2004-2006 cycle); and

Total shareholder return factors of 150% for both the 2004-2006 and 2005-2007 performance share cycles and 126.47% for the 2006-2008 performance share cycle.

Retirement/Voluntary Termination

Mr. Alexander (55), Mr. Marsh (55) and Mr. Morgan (56) are currently eligible for early retirement at or above age 55 with ten years of credited service. The earliest retirement age without reduction is age 60 for Mr. Alexander, Mr. Marsh, Mr. Morgan and Ms. Vespoli and age 65 for Mr. Grigg. Normal retirement age is 65. Mr. Grigg (58) and Ms. Vespoli (47) are not eligible for retirement in 2006 as Mr. Grigg does not meet the service requirement and Ms. Vespoli does not meet the minimum age requirement.

Mr. Grigg was hired in 2004 and based on the terms of his employment agreement, he will be eligible for retirement benefits at age 65. However, based on the employment agreement, Mr. Grigg and his spouse are eligible for retiree health care benefits in the event of a termination for any reason. In the event of a retirement/voluntary termination, the remaining named executive officers would not be entitled to any additional benefits generally not available to all salaried employees.

Retirement/Voluntary Termination

	Severance	STIP Award	Incremental Pension Benefit (present value)	Accelerated LTIP and Other Equity Awards	Health Care	Total
Anthony J. Alexander (retirement eligible)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Richard R. Grigg(1) (voluntary termination)	$ 0	$ 874,086	$ 0	$ 0	$ 136,450	$ 1,010,536
Richard H. Marsh (retirement eligible)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Stephen E. Morgan (retirement eligible)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Leila L. Vespoli (voluntary termination)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

In the event of an early retirement in the case of Mr. Alexander and Mr. Marsh, or in the event of a voluntary termination in the case of Mr. Grigg and Ms. Vespoli, the named executive officers shall be entitled to the following benefits generally not available to all salaried employees:

(1) Based on Mr. Grigg s employment agreement, he shall receive, in the event of a termination for any reason, a prorated portion of the STIP award based on the number of months employed in the year. In addition, Mr. Grigg will be granted the maximum credit for the purposes of determining the company contribution toward the cost of retiree health care coverage.

Severance

All named executive officers are covered under FirstEnergy s Executive Severance Benefits Plan. For the purposes of the plan, executives are offered severance benefits if involuntarily separated when business conditions require the closing of a facility, corporate restructuring, a reduction in workforce or job elimination. Severance is also offered if an executive rejects a job assignment that would result in a reduction in current base pay, contain a requirement that the executive must relocate his/her current residence for reasons related to the new job, or result in a daily commute from the executive s current residence to a new reporting location of more than one hour each way and that is more than 30 minutes longer than the executive s present commute.

Severance (Absent a Change in Control)

	Severance(1)	STIP Award	Incremental Pension Benefit (present value)	Accelerated LTIP and Other Equity Awards(2)	Health Care	Total
Anthony J. Alexander	$ 1,211,250	$ 0	$ 0	$ 0	$ 0	$ 1,211,250
Richard R. Grigg(3)(4)	$ 672,299	$ 0	$ 0	$ 2,454,446	$ 136,450	$ 3,263,195
Richard H. Marsh	$ 352,498	$ 0	$ 0	$ 0	$ 0	$ 352,498
Stephen E. Morgan	$ 288,606	$ 0	$ 0	$ 0	$ 0	$ 288,606
Leila L. Vespoli(5)	$ 295,099	$ 0	$ 1,264,893	$ 1,272,246	$ 0	$ 2,832,238

Mr. Alexander, Mr. Grigg, Mr. Marsh, Mr. Morgan and Ms. Vespoli shall be provided the following severance benefits generally not available to all salaried employees:

(1) An additional one and one-half weeks base pay for each full year of credited service. For the purposes of the severance plan the number of full years of credited service will be equal to the number of whole years of credited service under FirstEnergy s Pension Plan(s) as of January 1 of the year involuntarily severed plus the current year. The minimum severance amount is 52 weeks base pay.

Mr. Alexander, Mr. Marsh and Mr. Morgan are retirement eligible and would receive benefits available in retirement irrespective of a severance. Therefore, there is no incremental value represented in the table for these benefits. Mr. Grigg and Ms. Vespoli shall be provided the following severance benefits generally not available to all salaried employees:

(2) Mr. Grigg and Ms. Vespoli will receive Accelerated LTIP and Other Equity Awards payable as follows:

Performance shares granted in 2004 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the total shareholder return factor (150%) by the average of the high and low common stock price on the last trading day of the three-year performance cycle ($60.35). The incremental benefit is as follows: Vespoli $565,045. Mr. Grigg does not have a 2004-2006 performance share grant;

Performance shares granted in 2005 and 2006 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the December 31, 2006, estimated total shareholder return factors (150% and 126.47% for 2005 and 2006, respectively) by the average of the high and low common stock price for the thirty days prior to the date of termination ($60.81). The incremental benefit is as follows: Grigg $944,375 and Vespoli $478,785; and

Performance adjusted restricted stock units are prorated based on the number of full months in the restriction period with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the number of accelerated restricted stock units by the closing price of FirstEnergy s common stock on December 29, 2006 ($60.30). The incremental benefit is as follows: Grigg $683,862 and Vespoli $228,416.

(3) Mr. Grigg will be granted the maximum credit for the purposes of determining the FirstEnergy contribution toward the cost of retiree health coverage based on his employment agreement. Amount shown is calculated based on the assumptions used for financial reporting purposes under GAAP.

(4) Restricted stock shares generally are forfeited in a severance. However, the restriction on Mr. Grigg s restricted stock is lifted, and shares are payable in a severance scenario. The incremental benefit is $826,209.

(5) The Incremental Pension Benefit is the increased benefit provided to Ms. Vespoli from the SERP representing a reduced benefit she can receive as early as age 55.

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Change in Control

FirstEnergy executed agreements consistent with competitive practice with Mr. Marsh and Ms. Vespoli on December 31, 2003, with Mr. Alexander on March 5, 2004 and with Mr. Grigg on March 7, 2005. Mr. Morgan does not have Special Severance Agreements.

Generally, pursuant to the Special Severance Agreements, a change in control is deemed to occur:

(1) if any person acquires 50% or more of FirstEnergy s voting securities (or 25% or more of FirstEnergy s voting securities if such person proposes any individual for election to FirstEnergy s Board of Directors or such person already has a representative on FirstEnergy s Board of Directors), excluding acquisitions (i) directly from FirstEnergy, (ii) by FirstEnergy, (iii) by certain employee benefit plans, and (iv) pursuant to a transaction meeting the requirements of item (3) below; or

(2) if a majority of FirstEnergy s directors as of the date of the Special Severance Agreement are replaced (other than in specified circumstances); or

(3) upon the consummation of a reorganization, merger, consolidation, sale or other disposition of all or substantially all of FirstEnergy s assets, unless, following such transaction:

(a) the same person or persons who owned FirstEnergy s voting securities prior to the transaction own more than 75% of FirstEnergy s voting securities in the same proportions as their ownership prior to the transaction,

(b) no person or entity (with certain exceptions) owns 25% or more of FirstEnergy s voting securities, and

(c) at least a majority of the directors resulting from the transaction were directors at the time of the execution of the agreement providing for such transaction; or

(4) if the shareholders of FirstEnergy approve a complete liquidation or dissolution of FirstEnergy.

The change in control severance benefits are triggered only when the individual is terminated without cause or resigns for good reason. Good reason is defined as a material change, following a change in control, inconsistent with the individual s previous job duties or compensation. The following tables were prepared as though the named executive officers employment was terminated following the change in control.

Change In Control (Resigns for Good Reason)

	Severance(1)	STIP Award(2)	Incremental Pension Benefit (present value)(3)	Accelerated LTIP and Other Equity Awards(4)	Section 280G Gross-up(5)	Health Care(6)	Total
Anthony J. Alexander	$ 6,339,741	$ 0	$ 801,562	$ 15,800,586	$ 7,423,707	$ 0	$ 30,365,596
Richard R. Grigg	$ 3,976,671	$ 874,086	$ 1,176,635	$ 4,841,407	$ 4,310,253	$ 136,450	$ 15,315,502
Richard H. Marsh	$ 1,930,371	$ 0	$ 415,506	$ 2,037,307	$ 1,317,611	$ 39,800	$ 5,740,595
Stephen E. Morgan	$ 0	$ 0	$ 0	$ 1,603,111	$ 0	$ 0	$ 1,063,111
Leila L. Vespoli	$ 1,886,353	$ 435,414	$ 274,326	$ 6,068,701	$ 3,398,069	$ 25,839	$ 12,088,702

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Change In Control (Discharged without Cause/Severed)

	Severance(1)	STIP Award(2)	Incremental Pension Benefit (present value)(3)	Accelerated LTIP and Other Equity Awards(4)	Section 280G Gross-up(5)	Health Care(6)	Total
Anthony J. Alexander	$ 6,339,741	$ 0	$ 801,562	$ 15,800,586	$ 7,423,707	$ 0	$ 30,365,596
Richard R. Grigg	$ 3,976,671	$ 874,086	$ 1,176,635	$ 4,841,407	$ 4,310,253	$ 136,450	$ 15,315,502
Richard H. Marsh	$ 1,930,371	$ 0	$ 415,506	$ 2,037,307	$ 1,317,611	$ 39,800	$ 5,740,595
Stephen E. Morgan	$ 288,606	$ 0	$ 0	$ 1,603,111	$ 0	$ 0	$ 1,351,717
Leila L. Vespoli	$ 1,886,353	$ 435,414	$ 274,326	$ 6,068,701	$ 3,398,069	$ 25,839	$ 12,088,702

If, within a period of 36 full calendar months after a change in control of FirstEnergy, the named executive officer is discharged without cause or resigns for good reason, they shall be entitled to the following payments that generally are not available to all salaried employees:

(1) An amount equal to 2.99 multiplied by the sum of the amount of annual base salary at the rate in effect as of the date of termination plus the average three previous years incentive awards paid for Mr. Alexander $6,306,741; Mr. Marsh $1,916,371; and Ms. Vespoli $1,880,853. An amount equal to 2.99 multiplied by the sum of the amount of annual base salary at the rate in effect as of the date of termination plus the target annual short-term incentive amount in effect the year during which the date of termination occurs whether or not fully paid for Mr. Grigg $3,976,671. An additional lump sum cash payment as follows: Alexander $33,000; Grigg $0; Marsh $14,000; and Vespoli $5,500. This amount is included in the severance column. In the event of a resignation for good reason after a change in control, Mr. Morgan would not be entitled to severance pay. If Mr. Morgan was discharged without cause after a change in control, he would be entitled to severance pay based on the terms of FirstEnergy s Executive Severance Benefits Plan.

(2) Mr. Alexander, Mr. Marsh and Mr. Morgan are retirement eligible and would receive the short-term incentive award irrespective of a change in control. Mr. Grigg and Ms. Vespoli would receive a prorated portion of the STIP award based on the number of months employed in the year as follows: Mr. Grigg $874,086 and Ms. Vespoli $435,414.

(3) The Incremental Pension Benefit is the increased benefit provided to the named executive officer as a result of a change in control based on the terms of the Special Severance Agreements.

(4) Accelerated LTIP and Other Equity Awards are payable as follows:

Unvested stock options become immediately exercisable. The amounts shown are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the FirstEnergy s common stock on December 29, 2006 ($60.30). Alexander $3,999,450; Grigg $570,599; Marsh $915,757; Morgan $244,479; and Vespoli $869,714.

Performance shares granted in 2004 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the total shareholder return factor (150%) by the average of the high and low common stock price on the last trading day of the three-year performance cycle ($60.35). The incremental benefit is as follows: Alexander $0; Grigg $0; Marsh $0; Morgan $0; and Vespoli $565,044.

Performance shares granted in 2005 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the total shareholder return factor (150%) by the average of the high and low common stock price for the thirty days prior to the date of change in control ($60.81). The incremental benefit is as follows: Alexander $0; Grigg $695,213; Marsh $0; Morgan $0; and Vespoli $351,745.

Performance shares granted in 2006 are payable based on the change in control value protection rights as follows: the higher of (a) the account balance on the date of such termination of employment using the average high and low stock price for the prior thirty day period ($60.81) and the most recent total shareholder return factor (126.47%) or (b) the account balance on the date of the grant. The incremental benefit is as follows: Alexander $1,687,035; Grigg $747,486; Marsh $256,812; Morgan $113,107; and Vespoli $381,120.

Performance-adjusted and discretionary restricted stock units are payable as follows:
The restriction is lifted from restricted stock units granted in 2005. The 2006 grant is payable based on the share value protection rights in the agreement as follows: 1) a lump sum cash payment of the difference of the fair market value on the date of the change in control and the fair market value on the date of termination multiplied by the number of shares and 2) a payment of the total number of shares of common stock equal to the number of restricted stock units. The amounts shown are calculated by multiplying the number of accelerated restricted stock units by the closing price of the FirstEnergy s common stock on December 29, 2006 ($60.30). The incremental benefit is as follows: Alexander $4,045,226; Grigg $2,001,900; Marsh $793,970; Morgan $214,849; and Vespoli $670,898.

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The restriction is lifted from restricted stock shares. The 2006 grant is payable based on the share value protection rights in the agreement as follows: a cash payment if the fair market value of a share of stock on the date of grant or the fair market value of a share of stock on the date of the change in control is greater than the fair market value of a share of stock on the date of termination of employment. The cash payment is determined by subtracting the fair market value of a share of stock on the date of termination of employment from the greater of: (a) the fair market value of a share of stock on the date of grant, or (b) the fair market value of a share of stock on the date of the change in control. The difference is multiplied by the number of shares granted and paid within ten days of the termination of employment. The amounts shown are calculated by multiplying the number of accelerated restricted stock units by the closing price of FirstEnergy s common stock on December 29, 2006 ($60.30). The incremental benefit is as follows: Alexander $6,068,875; Grigg $826,209; Morgan $479,747; and Vespoli $3,197,926. Mr. Marsh does not have restricted stock.

In the event of a change in control, the 20% FirstEnergy matching contribution in the stock account of the EDCP described earlier in this prospectus would fully vest. Matching contributions made by FirstEnergy payable under the EDCP are as follows: Marsh $70,768; Morgan $10,929; and Vespoli $32,254.

(5) The Section 280G Gross-up represents the estimated excise tax charged to the named executive officer upon receiving any change in control payments.

(6) Mr. Marsh will be credited with three years of age and service, which will provide him with the maximum points for the purposes of determining the company contribution toward the cost of retiree health coverage. Mr. Grigg will be granted the maximum number of points based on his employment agreement for the purposes of health care for the purposes of determining the company contribution toward the cost of retiree health coverage. Ms. Vespoli will be provided health coverage at active employee rates for three years following termination after a change in control based on the Special Severance Agreements under Change in Control above. Amounts shown are calculated based on the assumptions used for financial reporting purposes under GAAP.

Death/Disability

Death/Disability

	Severance	STIP Award	Incremental Pension Benefit (present value)(1)	Accelerated LTIP and Other Equity Awards(2)	Executive Supplemental Life Insurance Death Benefit(3)	Health Care(8)	Total
Anthony J. Alexander	$ 0	$ 0	$ 0	$ 14,113,551	$ 656,000	$ 0	$ 14,769,551
Richard R. Grigg(4)	$ 0	$ 0	$ 0	$ 4,343,083	$ 0	$ 136,450	$ 4,479,533
Richard H. Marsh	$ 0	$ 0	$ 0	$ 1,709,727	$ 359,000	$ 0	$ 2,068,727
Stephen E. Morgan	$ 0	$ 0	$ 0	$ 939,075	$ 192,920	$ 0	$ 1,131,995
Leila L. Vespoli	$ 0	$ 0	$ 2,060,905	$ 5,782,367	$ 323,000	$ 0	$ 8,166,272

The death/disability benefits have been combined because the benefits provided are generally similar in nature, with the following exceptions:

There is no enhanced benefit from the Supplemental Plan or the SERP in the event of a disability, and

The Executive Supplemental Life Insurance Death Benefit is only payable upon death.

The death/disability benefits provided to the named executive officers are provided on a non-discriminatory basis to all salaried employees generally upon eligible termination of employment, with the following exceptions:

(1) The Incremental Pension Benefit is the increased benefit provided to Ms. Vespoli as a result of death and includes the enhanced spousal benefit from the Supplemental Plan and the SERP. There is no enhanced benefit in the event of a disability. Mr. Alexander, Mr. Marsh and Mr. Morgan are retirement eligible, and Mr. Grigg is not retirement eligible so there is no incremental pension benefit in the event of death or disability.

(2) Accelerated LTIP and Other Equity Awards are payable as follows:

Unvested stock options become immediately exercisable upon death. Unvested options continue to vest according to the vesting schedule upon disability. The amounts shown are calculated by multiplying the number of accelerated/unvested options by the difference between the exercise price and the closing price of FirstEnergy s common stock on December 29, 2006 ($60.30): Alexander $3,999,450; Grigg $570,599; Marsh $915,757; Morgan $244,479; and Vespoli $869,713.

Performance shares granted in 2004 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the total shareholder return factor (150%) by the average of the high and low common stock price on the last trading day of the three-year performance cycle ($60.35). The incremental benefit is as follows: Vespoli $565,045. Mr. Grigg does not have a 2004-2006 performance share grant.

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Performance shares granted in 2005 and 2006 are prorated based on the number of full months in the performance cycle with a minimum of 12 months to be eligible. The amounts shown are calculated by multiplying the accelerated number of shares by the total shareholder return factor (150% and 126.47% for 2005 and 2006, respectively) by the average of the high and low common stock price for the thirty days prior to the date of termination ($60.81) The incremental benefit is as follows: Grigg $944,375 and Vespoli $478,785.

The restriction is lifted from all performance-adjusted and discretionary restricted stock units and restricted stock shares. The amounts shown are calculated by multiplying the number of accelerated restricted stock units and restricted stock by the closing price of FirstEnergy s common stock on December 29, 2006 ($60.30), and subtracting the amount of benefit provided in voluntary termination or retirement scenario as appropriate. The incremental benefit is as follows: Alexander $10,114,101; Grigg $2,828,109; Marsh $793,970; Morgan $694,596; and Vespoli $3,868,824.

(3) The Executive Supplemental Life Insurance Death Benefit is payable in the event of death.

(4) Mr. Grigg will be granted the maximum number of points based on his employment agreement for the purposes of health care for the purposes of determining FirstEnergy s contribution toward the cost of retiree health coverage. Amount shown is calculated based on the assumptions used for financial reporting purposes under GAAP.

Compensation of Directors

In 2006, the following individuals served on our Board of Directors: Bradley S. Ewing, Charles E. Jones, Jr., Mark A. Julian, Stephen E. Morgan, Gelorma E. Persson, Stanley C. Van Ness and Leila L. Vespoli. Only non-employee directors are compensated for their membership on our Board of Directors. Since Bradley S. Ewing, Charles E. Jones Jr., Mark A. Julian, Stephen E. Morgan and Leila L. Vespoli were employees of FirstEnergy, they did not receive compensation for their service as members of our Board of Directors in 2006. Ms. Persson and Mr. Van Ness received a $15,000 annual cash retainer, $1,000 cash for each regularly scheduled meeting and $1,000 cash for each special meeting. The following table sets forth the compensation paid to our non-employee directors for 2006.

Director Compensation

As of December 31, 2006

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(1) ($)	All Other Compensation ($)	Total ($)
Gelorma E. Persson(2)	$ 26,000	$ 0	$ 0	$ 0	$ 15,414	$ 0	$ 41,414
Stanley C. Van Ness(3)	$ 22,000	$ 0	$ 0	$ 0	$ 0	$ 0	$ 22,000

(1) Represents the above-market earnings on compensation that are deferred on a basis that is not tax-qualified. The formula used to determine the above market earnings equals (2006 total interest x {difference in the 1999 Applicable Federal Rate for long-term rates, or AFR, and the plan rate}) divided by the plan rate.

(2) Ms. Persson received fees as follows: $15,000 annual retainer, $8,000 in regular meeting fees and $3,000 in special meeting fees.

(3) Mr. Van Ness received fees as follows: $15,000 annual retainer, $5,000 in regular meeting fees and $2,000 in special meeting fees. Mr. Van Ness served as Director in 2006 and 2007 until his death September 21, 2007.

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Security Ownership of Management

The following table shows shares of FirstEnergy stock beneficially owned as of September 30, 2007, by each director; the executive officers named in the Summary Compensation Table above; and all directors and executive officers as a group. Also listed, as of that date, are common stock equivalents credited to executive officers as a result of participation in incentive compensation plans. None of the shares below are pledged by the directors or named executive officers.

Name	Class of Stock	Shares Beneficially Owned(1)	Common Stock Equivalents(2)
Anthony J. Alexander	Common	551,587	295,490
Bradley S. Ewing	Common	12,446	16,944
Richard R. Grigg	Common	49,364	86,479
Mark A. Julian	Common	20,847	18,636
Richard H. Marsh	Common	739	64,154
Stephen E. Morgan	Common	37,459	15,965
Gelorma E. Persson	Common	0	0
Donald R. Schneider	Common	17,503	57,897
Leila L. Vespoli	Common	177,702	54,439
Jesse T. Williams, Sr.	Common	15,733	0
All Directors and Executive Officers as a Group	Common	1,020,940	647,666

(1) Shares beneficially owned include (a) any shares with respect to which the person has a direct or indirect pecuniary interest, and (b) shares that the person has the right to acquire beneficial ownership within 60 days of September 30, 2007, and are as follows: (Alexander 363,275 shares; Ewing none; Grigg 41,069 shares; Julian none; Marsh none; Morgan 28,825 shares; Persson none; Schneider none; Vespoli 116,600 shares; Williams none; and all directors and executive officers as a group 667,182 shares). The percentage of shares beneficially owned by any director or nominee, or by all directors and executive officers as a group, does not exceed 1% of the class owned. Each individual or member of the group has sole voting and investment power with respect to the shares beneficially owned.

(2) Common stock equivalents represent the cumulative number of shares deferred under the EDCP, performance shares and restricted stock units credited to each executive officer. The value of these shares is measured, in part, by the market price of FirstEnergy s common stock. Final payments for performance shares may vary due to performance factors, as discussed under Long-Term Incentive Program above. In regard to performance-adjusted restricted stock units, at the end of the restriction period, the actual number of shares issuable may be adjusted upward or downward by 25% based on FirstEnergy s performance against three predetermined metrics. In addition, the common stock equivalents reflected for All Directors and Executive Officers as a Group includes discretionary restricted stock units awarded to certain executive officers that will be issuable five years after the date awarded, except for specified provisions if the executive dies, is terminated due to disability or there is a change in control. Common stock equivalents do not have voting rights or other rights associated with ownership of common stock.

Compensation Committee Interlocks and Insider Participation

FirstEnergy designs, evaluates and administers all compensation plans for us and other subsidiaries. FirstEnergy s Board of Directors and/or FirstEnergy s Compensation Committee reviews and approves all compensation for FirstEnergy and its subsidiaries, including us. We do not establish our own executive compensation policy and procedures, and our Board of Directors does not have a separate Compensation Committee. No members of the FirstEnergy Compensation Committee meet the criteria to be considered for an interlock or insider participation. The members of the FirstEnergy Compensation Committee include: Catherine A. Rein (Chair), Dr. Carol A. Cartwright, Robert B. Heisler, Jr., Russell W. Maier and Wes M. Taylor.

Director Independence

The following directors are not independent because each of them is either our employee or an employee of FirstEnergy or one of its other subsidiaries: Stephen E. Morgan, Bradley S. Ewing, Mark A. Julian and Donald R. Schneider.

Jesse T. Williams, Sr., one of our non-employee directors and a director of FirstEnergy, was determined by FirstEnergy s Board of Directors to be independent by reference to the definition of an independent director as

promulgated from time to time by the NYSE and the SEC. The definition used by the FirstEnergy Board of Directors to determine independence, which includes all elements of independence set forth by the NYSE and SEC, is included in its Corporate Governance Policies and can be viewed by visiting FirstEnergy s website at www.firstenergycorp.com/ir. The information on the FirstEnergy website does not constitute part of this prospectus.

Although neither our Board of Directors, nor FirstEnergy s Board of Directors, has made any formal determination of the independence of Gelorma E. Persson, our other non-employee director, nor is any such determination required by any standard applicable to us, we believe that Ms. Persson would likely be considered independent under the definition referred to above. Ms. Persson and Mr. Williams serve on our Board of Directors primarily to satisfy NJBPU requirements that we have outside directors not affiliated with our parent company, FirstEnergy.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Based on its size and varied business operations, FirstEnergy and its subsidiaries, including us, may from time to time engage in transactions and business arrangements with companies and other organizations in which one of the members of their Board of Directors, executive officers or their respective immediate family members also may be a board member, executive officer or significant investor, or in which such person has a direct or indirect material interest. FirstEnergy recognizes that related person transactions have the potential to create perceived or actual conflicts of interest and could create the appearance that decisions are based on considerations other than the best interests of FirstEnergy and its shareholders. Accordingly, as a general matter, it is FirstEnergy s preference to avoid related person transactions. However, there are situations where related person transactions are either in, or not inconsistent with, FirstEnergy s best interests and the best interests of its shareholders. FirstEnergy s Board of Directors has determined that it is, therefore, appropriate and necessary to have a review process in place with respect to any related person transactions.

Based on the foregoing, the FirstEnergy Board of Directors established a Related Person Transactions Policy to be implemented by its Corporate Governance Committee, in order to effectuate the review, approval, and ratification process surrounding related person transactions. For purposes of this discussion any reference to the Corporate Governance Committee is a reference to the FirstEnergy Corporate Governance Committee. This Policy supplements FirstEnergy s other conflict of interest policies set forth in the FirstEnergy Conflicts-Of-Interest Policy, Code of Business Conduct, and Board of Directors Code of Ethics and Business Conduct. Related person transactions shall be consummated or shall continue only if a majority of the disinterested members of the Corporate Governance Committee or the FirstEnergy Board of Directors approves or ratifies the transaction in accordance with this Policy. In making its decisions, the Corporate Governance Committee will review transactions and proposed transactions submitted for approval by our management, who will have internally reviewed the submitted transactions by taking into consideration the Policy, which includes the definitions and terms set forth in Item 404 of Regulation S-K under the federal securities laws.

As part of this Policy, the management of FirstEnergy and its subsidiaries has established review procedures for any transaction or proposed transaction, in which FirstEnergy or any of its subsidiaries are currently, or may be, a participant in which the amount exceeds $120,000, and in which the related person, as defined in Item 404 of Regulation S-K, had or will have a direct or indirect material interest or any amendment to such a transaction. FirstEnergy and its subsidiaries also have established procedures to identify such related persons. The identities of these related persons will be distributed to business units and function/department leaders to ensure senior management is made aware of any transaction or proposed transaction involving FirstEnergy and its subsidiaries and anyone on that list. Management will bring any such transactions to the attention of the Corporate Governance Committee for its review, approval or ratification.

When reviewing a proposed transaction, the Corporate Governance Committee will review the material facts of the related person s relationship to FirstEnergy and its subsidiaries, his or her interest in the proposed transaction, and any other material facts of the proposed transaction, including, but not limited to, the aggregate value and benefits of such transaction to FirstEnergy and its subsidiaries, the availability of other sources of comparable products or services (if applicable), and an assessment of whether the transaction is on terms that are the same as, or comparable to, the terms available to an unrelated third party or to employees generally. Additionally, the Corporate Governance Committee requires FirstEnergy s CEO to review the business merits of the transaction prior to its review.

During fiscal year 2006, we participated in the transactions described below, in which the amount involved exceeded $120,000 and in which any director, executive officer or a member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest.

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In 2006, Kimberly F. Jones, wife of FirstEnergy executive officer, Charles E. Jones, Jr., served as Director, Corporate Services Supply Chain of FirstEnergy. In 2006, she was paid a base salary of $159,800 and was issued a performance share grant of 165 performance shares (a value of $7,990), 628 performance-adjusted restricted stock units (a value of $31,978) and 99 discretionary restricted stock units (a value of $5,041). Her incentive compensation bonus payout was $36,650. Mrs. Jones was employed by FirstEnergy prior to her marriage to Mr. Jones, and her compensation is commensurate to employees with comparable qualifications and responsibilities and is consistent with the terms of FirstEnergy programs governing that element of compensation. No reporting relationship exists between Mrs. Jones and Mr. Jones.

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DESCRIPTION OF THE EXCHANGE NOTES

The following is a summary of certain terms of the Exchange Notes, does not purport to be complete, and is subject to, and qualified in its entirety by reference to the provisions of the senior note indenture and the forms of Exchange Notes established pursuant to the senior note indenture, both of which are filed as exhibits to the registration statement of which this prospectus is a part, and the Trust Indenture Act. Certain capitalized terms used in this prospectus are defined in the senior note indenture.

General

The form and terms of the Exchange Notes are identical in all material respects to the form and terms of the Original Notes except that the Exchange Notes (1) will be registered under the Securities Act, (2) will not be subject to the restrictions on transfer applicable to the Original Notes, (3) will bear different CUSIP numbers and (4) will not be entitled to the rights of holders of Original Notes under the registration rights agreement, including additional interest.

The Original Notes were, and the Exchange Notes will be, issued as a series of senior notes under the senior note indenture. Prior to the release date referred to below, all of the senior notes outstanding under the senior note indenture were secured by a like principal amount of our senior note mortgage bonds issued and delivered by us to the senior note trustee. As used in this prospectus, senior note mortgage bonds means the FMB previously issued under and secured by our Indenture, dated as of March 1, 1946, or the Mortgage, to The Bank of New York, as successor mortgage trustee, as heretofore amended and supplemented.

As of March 31, 2007, we had $937.2 million aggregate principal amount of FMB outstanding, of which $650 million aggregate principal amount constituted senior note mortgage bonds held by the senior note trustee and subject to release on the release date (as described under Security and Release Date below). On May 14, 2007, as a result of our exercise of our rights to optionally redeem $125 million of outstanding FMB, the release date occurred, and, at our request, the senior note trustee surrendered all senior note mortgage bonds for cancellation. In addition, we terminated the Mortgage as of September 14, 2007 because no FMB remained outstanding.

Security and Release Date

Prior to the release date, which occurred on May 14, 2007, all of the senior notes issued under the senior note indenture were secured by a like principal amount of our senior note mortgage bonds issued and delivered by us to the senior note trustee. On the release date, the senior note trustee surrendered all senior note mortgage bonds for cancellation, and all then outstanding senior notes ceased to be secured by senior note mortgage bonds. Upon issuance, the Exchange Notes will be our unsecured general obligations and will rank on parity with our unsecured and unsubordinated indebtedness, including all other senior notes.

The release date occurred due to the satisfaction of the condition that the senior note trustee held senior note mortgage bonds constituting not less than 80% in aggregate principal amount of all outstanding FMB.

Under the terms of the senior note indenture, we were not permitted to issue FMB other than as senior note mortgage bonds securing senior notes. We are permitted, however, to incur additional other secured debt subject to the limitation on liens provision of the senior note indenture. See Certain Covenants Limitation on Liens below. As described above, the Mortgage has been terminated.

Maturity, Interest Rate and Interest Payment Dates

The 2017 Exchange Notes will mature on June 1, 2017, and the 2037 Exchange Notes will mature on June 1, 2037. In each case unless earlier redeemed as described under Optional Redemption below.

Interest on the Exchange Notes of each series will:

- be payable in U.S. dollars at the rate of 5.65% per annum with respect to the 2017 Exchange Notes and at the rate of 6.15% per annum with respect to the 2037 Exchange Notes;
- be computed for each interest period on the basis of a 360-day year consisting of twelve 30-day months and for any period shorter than a full month, on the basis of the actual number of days elapsed in such period;
- be payable semi-annually in arrears on each June 1 and December 1, beginning on December 1, 2007 and at maturity;
- initially accrue from, and include, the date of original issuance (i.e., May 21, 2007); and
- be paid to the person in whose names the senior notes are registered at the close of business on the regular record date, which is the business day immediately preceding each interest payment date, so long as the senior notes are issued in book-entry only form. Otherwise, the record date will be the fifteenth calendar day next preceding each interest payment date. We shall not be required to make transfers or exchanges of Exchange Notes for a period of 15 calendar days next preceding an interest payment date.

Optional Redemption

The Exchange Notes of each series will be redeemable as a whole or in part, at our option, at any time, at a redemption price equal to the greater of:

- 100% of the principal amount of such Exchange Notes being redeemed, or
- as determined by the Independent Investment Banker (as defined below), the sum of the present values of the Remaining Scheduled Payments (as defined below), discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 20 basis points in the case of the 2017 Exchange Notes and plus 25 basis points in the case of the 2037 Exchange Notes,

plus, in each case, accrued and unpaid interest on such Exchange Notes to the date of redemption.

Adjusted Treasury Rate means, with respect to any redemption date:

- the yield, under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated H.15(519) or any successor publication which is published weekly by the Board of Governors of the Federal Reserve System and which establishes yields on actively traded United States Treasury securities adjusted to constant maturity under the caption Treasury Constant Maturities, for the maturity corresponding to the Comparable Treasury Issue (if no maturity is within three months before or after the Remaining Life, yields for the two published maturities most closely corresponding to the Comparable Treasury Issue shall be determined and the Adjusted Treasury Rate shall be interpolated or extrapolated from these yields on a straight line basis, rounding to the nearest month); or if the release (or any successor release) is not published during the week preceding the calculation date or does not contain these yields, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date. The Adjusted Treasury Rate will be calculated on the third business day preceding the redemption date.

Comparable Treasury Issue means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of the Exchange Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such securities, or Remaining Life.

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Comparable Treasury Price means (i) the average of three Reference Treasury Dealer Quotations for the redemption date, after excluding the highest and lowest Reference Treasury Dealer Quotations, or (ii) if the Independent Investment Banker obtains fewer than three Reference Treasury Dealer Quotations, the average of all such quotations.

Independent Investment Banker means one of the Reference Treasury Dealers appointed by us.

Reference Treasury Dealer means:

- each of Barclays Capital Inc., J.P. Morgan Securities Inc. and UBS Securities LLC and their respective successors; provided, however, that if any of the foregoing cease to be a primary U.S. Government securities dealer in the United States, or a Primary Treasury Dealer, we will substitute therefor another Primary Treasury Dealer; and

- any other Primary Treasury Dealer selected by the Independent Investment Banker after consultation with us.

Reference Treasury Dealer Quotations means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker at 5:00 p.m., New York City time, on the third business day preceding the redemption date.

Remaining Scheduled Payments means, with respect to the Exchange Notes to be redeemed, the remaining scheduled payments of principal of and interest on such Exchange Notes that would be due after the related redemption date but for such redemption. If such redemption date is not an interest payment date with respect to such Exchange Notes, the amount of the next succeeding scheduled interest payment on such Exchange Notes will be reduced by the amount of interest accrued on such Exchange Notes to such redemption date.

We will mail notice of any redemption between 30 days and 60 days before the redemption date to each holder of the Exchange Notes to be redeemed.

Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the Exchange Notes or portions thereof called for redemption.

Events of Default

The following constitute events of default under the senior note indenture:

- default in the payment of principal of and premium, if any, on any senior note when due and payable;

- default in the payment of interest on any senior note when due which continues for 60 days;

- default in the performance or breach of any of our other covenants or agreements in the senior notes or in the senior note indenture and the continuation of the default for 90 days after we have received written notice of the default either from the senior note trustee or from the holders of at least 33% in aggregate principal amount of the outstanding senior notes; and

- certain events of bankruptcy, insolvency, reorganization, assignment or receivership relating to us.

If an event of default occurs and is continuing, either the senior note trustee or the holders of a majority in aggregate principal amount of the outstanding senior notes may declare the principal amount of and interest on all of the senior notes to be due and payable immediately. At any time after an acceleration of the senior notes has been declared, if we pay or deposit with the senior note trustee a sum sufficient to pay all matured installments of interest and the principal and any premium which has become due on the senior notes otherwise

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than by acceleration and all defaults have been cured or waived, then our payment or deposit will cause an automatic rescission and annulment of the acceleration of the senior notes.

The senior note indenture provides that the senior note trustee generally will be under no obligation to exercise any of its rights or powers under the senior note indenture at the request or direction of any of the holders of the senior notes unless those holders have offered to the senior note trustee security or indemnity reasonably satisfactory to it. Subject to the provisions for indemnity and certain other limitations contained in the senior note indenture, the holders of a majority in aggregate principal amount of the outstanding senior notes generally will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the senior note trustee, or of exercising any trust or power conferred on the senior note trustee. The holders of a majority in aggregate principal amount of the outstanding senior notes generally will have the right to waive any past default or event of default (other than a payment default) on behalf of all holders of the senior notes. The senior note indenture provides that no holder of the senior notes may institute any action against us under the senior note indenture unless it has previously given to the senior note trustee written notice of the occurrence and continuance of an event of default and unless the holders of a majority in aggregate principal amount of the senior notes then outstanding affected by the event of default have requested the senior note trustee to institute the action and have offered the senior note trustee reasonable indemnity, and the senior note trustee has not instituted the action within 60 days of the request. Furthermore, no holder of the senior notes will be entitled to institute any action if and to the extent that the action would disturb or prejudice the rights of other holders of the senior notes. Notwithstanding that the right of a holder of the senior notes to institute a proceeding with respect to the senior note indenture is subject to certain conditions precedent, each holder of a senior note has the right, which is absolute and unconditional, to receive payment of the principal of, and premium, if any, and interest on the senior note when due and to institute suit for the enforcement of such payment, and those rights may not be impaired without the consent of the affected holders of senior notes.

The senior note indenture provides that the senior note trustee, within 90 days after the occurrence of a default with respect to the senior notes, is required to give holders of the senior notes notice of any default known to the senior note trustee, unless cured or waived, but, except in the case of default in the payment of principal of, or premium, if any, or interest on, any senior notes, the senior note trustee may withhold notice if it determines in good faith that it is in the interest of holders of those senior notes to do so. We are required to deliver to the senior note trustee each year an officer s certificate as to whether or not we are in compliance with the conditions and covenants under the senior note indenture.

Modification with Consent of Holders

Modification and amendment of the senior note indenture may be effected by us and the senior note trustee with the consent of the holders of a majority in aggregate principal amount of the outstanding senior notes, provided that no modification or amendment may, without the consent of the holder of each outstanding senior note affected by such modification or amendment,

- change the maturity date of such senior notes;
- reduce the rate or extend the time of payment of interest on such senior notes;
- reduce the principal amount of, or premium payable on, such senior notes;
- change the coin or currency of any payment of principal of, or premium, if any, or interest on, such senior notes;
- change the date on which such senior notes may be redeemed or repaid at the option of their holders or adversely affect the rights of a holder to institute suit for the enforcement of any payment on or with respect to such senior notes; or
- modify the foregoing requirements or reduce the percentage of outstanding senior notes necessary to modify or amend the senior note indenture or to waive any past default to less than a majority.

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Modification without Consent of Holders

Modification and amendment of the senior note indenture may be effected by us and the senior note trustee without the consent of the holders of any senior notes:

- to add to our covenants for the benefit of the holders or to surrender a right conferred on us in the senior note indenture;
- to add further security for the senior notes;
- to supply omissions, cure ambiguities or correct defects, which actions, in each case, are not prejudicial to the interest of the holders in any material respect; or
- to make any other change that is not prejudicial to the holders of the senior notes in any material respect.

A supplemental indenture which changes or eliminates any covenants or other provision of the senior note indenture (or any supplemental indenture) which has expressly been included solely for the benefit of one or more series of the senior notes, or which modifies the rights of the holders of the senior notes of one or more series with respect to that covenant or provision, will be deemed not to affect the rights under the senior note indenture of the holders of the senior notes of any other series.

Defeasance and Discharge

The senior note indenture provides that we will be discharged from any and all obligations in respect to the senior notes and the senior note indenture (except for certain obligations such as obligations to register the transfer or exchange of the senior notes, replace stolen, lost or mutilated senior notes and maintain paying agencies) if, among other things, we irrevocably deposit with the senior note trustee, in trust for the benefit of the holders of senior notes, money or certain United States government obligations, or any combination of money and certain United States government obligations, which will provide money in an amount sufficient, without reinvestment, to make all payments of principal of, premium, if any, and interest on, the senior notes on the dates payments are due in accordance with the terms of the senior note indenture and the senior notes; provided that unless all of the senior notes mature within 90 days of the deposit by redemption or otherwise, we will also have delivered to the senior note trustee an opinion of counsel to the effect that the holders of the senior notes will not recognize income, gain or loss for federal income tax purposes as a result of the defeasance or discharge of the senior note indenture. After we have been discharged from our obligations under the senior note indenture, the holders of the senior notes may look only to the deposit for payment of the principal of, and interest and any premium on, the senior notes.

Consolidation, Merger and Sale or Disposition of Assets

We may not consolidate with or merge into any other corporation or entity or sell or otherwise dispose of our properties as or substantially as an entirety unless:

- the successor or transferee corporation is a corporation or other entity organized and existing under the laws of the United States or any state of the United States or the District of Columbia; and
- the successor or transferee corporation or other entity assumes by supplemental indenture the due and punctual payment of the principal of and premium, if any, and interest on the senior notes and the performance of every covenant of the senior note indenture to be performed or observed by us.

Upon any consolidation, merger, sale, transfer or other disposition of our properties substantially as an entirety, permissible under the provision described in the immediately preceding paragraph, the successor corporation formed by the consolidation or into which we are merged or to which the transfer is made will succeed to us, and be substituted for us, and may exercise every right and power of ours, under the senior note indenture with the same effect as if the successor corporation had been named as Jersey Central Power & Light Company in the senior note indenture, and we will be released from all obligations under the senior note indenture. For purposes of the senior note indenture, the conveyance or other transfer by us of (i) all or any portion of our facilities for the generation of electric energy or (ii) all of our facilities for the transmission of electric energy, in each case considered alone or in any combination with properties described in the other clause, will in no event be deemed to constitute a conveyance or other transfer of all our properties, as or substantially as an entirety.

Certain Covenants

Limitation on Liens

The senior note indenture provides that, so long as any senior notes are outstanding, we may not issue, assume, guarantee or permit to exist any Debt (as defined below) that is secured by any mortgage, security interest, pledge or lien, or Lien, of or upon any of our Operating Property (as defined below), whether owned at the date of the senior note indenture or subsequently acquired, without effectively securing such senior notes (together with, if we so determine, any of our other indebtedness ranking equally with such senior notes) equally and ratably with that Debt (but only so long as that Debt is so secured).

The foregoing restriction will not apply to:

(1) Liens on any Operating Property existing at the time of its acquisition (which Liens may also extend to subsequent repairs, alterations and improvements to that Operating Property);

(2) Liens on Operating Property of a corporation existing at the time the corporation is merged into or consolidated with, or at the time the corporation disposes of its properties (or those of a division) as or substantially as an entirety to, us;

(3) Liens on Operating Property to secure the costs of acquisition, construction, development or substantial repair, alteration or improvement of property or to secure Debt incurred to provide funds for any of those purposes or for reimbursement of funds previously expended for any of those purposes, provided the Liens are created or assumed contemporaneously with, or within 18 months after, the acquisition or the completion of substantial repair or alteration, construction, development or substantial improvement;

(4) Liens in favor of any state or any department, agency or instrumentality or political subdivision of any state, or for the benefit of holders of securities issued by any such entity (or providers of credit enhancement with respect to those securities), to secure any Debt (including, without limitation, our obligations with respect to industrial development, pollution control or similar revenue bonds) incurred for the purpose of financing or refinancing all or any part of the purchase price or the cost of substantially repairing or altering, constructing, developing or substantially improving our Operating Property;

(5) Liens to compensate the senior note trustee as provided in the senior note indenture; or

(6) any extension, renewal or replacement (or successive extensions, renewals or replacements), in whole or in part, of any Lien referred to in clauses (1) through (5); provided, however, that the principal amount of Debt secured thereby and not otherwise authorized by clauses (1) through (5), must not exceed the principal amount of Debt, plus any premium or fee payable in connection with the extension, renewal or replacement, so secured at the time of the extension, renewal or replacement.

However, the foregoing restriction will not apply to our issuance, assumption or guarantee of Debt secured by a Lien which would otherwise be subject to the foregoing restriction up to an aggregate amount which, together with all other of our secured Debt (not including secured Debt permitted under any of the foregoing exceptions) and the Value (as defined below) of Sale and Lease-Back Transactions (as defined below) existing at that time (other than Sale and Lease-Back Transactions the proceeds of which have been applied to the retirement of certain indebtedness, Sale and Lease-Back Transactions in which the property involved would have been permitted to be subjected to a Lien under any of the foregoing exceptions in clauses (1) to (6) and Sale and Lease-Back Transactions that are permitted by the first sentence of Limitation on Sale and Lease-Back Transactions below), does not exceed the greater of 15% of Tangible Assets and 15% of Capitalization (as those

terms are defined below), in each case, determined in accordance with GAAP and as of a date not more than 60 days prior to such issuance, assumption or guarantee of debt. As of September 30, 2007, our Tangible Assets were approximately $5.414 billion and our Capitalization was approximately $4.589 billion.

Limitation on Sale and Lease-Back Transactions

The senior note indenture provides that so long as any senior notes are outstanding, we may not enter into or permit to exist any Sale and Lease-Back Transaction with respect to any Operating Property (except for transactions involving leases for a term, including renewals, of not more than 48 months), if the purchasers commitment is obtained more than 18 months after the later of the completion of the acquisition, construction or development of that Operating Property or the placing in operation of that Operating Property or of that Operating Property as constructed or developed or substantially repaired, altered or improved.

This restriction will not apply if:

- we would be entitled pursuant to any of the provisions described in clauses (1) to (6) of the first sentence of the second paragraph under Limitation on Liens above, to issue, assume, guarantee or permit to exist Debt secured by a Lien on that Operating Property without equally and ratably securing the senior notes;

- after giving effect to a Sale and Lease-Back Transaction, we could incur pursuant to the provisions described in the second sentence of the second paragraph under Limitation on Liens above, at least $1.00 of additional Debt secured by Liens (other than Liens permitted by the preceding paragraph); or

- we apply within 180 days an amount equal to, in the case of a sale or transfer for cash, the net proceeds (not exceeding the net book value), and, otherwise, an amount equal to the fair value (as determined by our Board of Directors) of the Operating Property so leased, to the retirement of senior notes or other Debt of ours ranking equally with the senior notes, subject to reduction for senior notes and Debt retired during the 180-day period otherwise than pursuant to mandatory sinking fund or prepayment provisions and payments at stated maturity.

Certain Definitions

Capitalization means the total of all the following items appearing on, or included in, our consolidated balance sheet: (i) liabilities for indebtedness maturing more than 12 months from the date of determination; and (ii) common stock, preferred stock, Hybrid Preferred Securities, premium on capital stock, capital surplus, capital in excess of par value, and retained earnings (however the foregoing may be designated), less, to the extent not otherwise deducted, the cost of shares of capital stock reacquired by us.

Debt means any outstanding debt for money borrowed evidenced by notes, debentures, bonds, or other securities, or guarantees of any thereof.

Operating Property means (i) any interest in real property owned by us and (ii) any asset owned by us that is depreciable in accordance with GAAP excluding, in either case, any interest of ours as lessee under any lease (except for a lease that results from a Sale and Lease-Back Transaction) which has been or would be capitalized on our books in accordance with GAAP.

Sale and Lease-Back Transaction means any arrangement with any person providing for the leasing to us of any Operating Property (except for leases for a term, including any renewals, of not more than 48 months), which Operating Property has been or is to be sold or transferred by us to such person; provided, however, Sale and Lease-Back Transaction does not include any arrangement first entered into prior to the date of the senior note indenture.

Tangible Assets means the amount shown as total assets on our consolidated balance sheet, less the following: (i) intangible assets including, but without limitation, goodwill, trademarks, trade names, patents and unamortized debt discount and expense and (ii) appropriate adjustments, if any, on account of minority interests. Tangible Assets will be determined in accordance with GAAP and practices applicable to the type of business in which we are engaged and that are approved by the independent accountants we regularly retain, and may be determined as of a date not more than 60 days prior to the happening of the event for which the determination is being made.

Value means, with respect to a Sale and Lease-Back Transaction, as of any particular time, the amount equal to the greater of (i) the net proceeds to us from the sale or transfer of the property leased pursuant to the Sale and Lease-Back Transaction and (ii) the net book value of the property leased, as determined by us in accordance with GAAP, in either case multiplied by a fraction, the numerator of which will be equal to the number of full years of the term of the lease that is part of the Sale and Lease-Back Transaction remaining at the time of determination and the denominator of which will be equal to the number of full years of the term of the lease, without regard, in any case, to any renewal or extension options contained in the lease.

Resignation or Removal of Senior Note Trustee

The senior note trustee may resign at any time by giving written notice to us specifying the day upon which the resignation is to take effect and that resignation will take effect immediately upon the later of the appointment of a successor senior note trustee and the day specified by the senior note trustee.

The senior note trustee may be removed at any time by an instrument or concurrent instruments in writing delivered to the senior note trustee and signed by the holders, or their attorneys in fact, representing a majority in principal amount of the then outstanding senior notes. In addition, so long as no event of default under the senior note indenture or event which, with the giving of notice or lapse of time or both, would become an event of default has occurred and is continuing, we may remove the senior note trustee upon written notice to the holder of each senior note outstanding and the senior note trustee, and upon the appointment of a successor senior note trustee.

Concerning the Senior Note Trustee

The Bank of New York Trust Company, N.A. is the successor senior note trustee under the senior note indenture. The senior note indenture provides that our obligations to compensate the senior note trustee and reimburse the senior note trustee for expenses, disbursements and advances will constitute indebtedness which will be secured by a lien generally prior to that of the senior notes upon all property and funds held or collected by the senior note trustee as such.

The senior note indenture provides that the senior note trustee shall be subject to and shall comply with the provisions of Section 310(b) of the Trust Indenture Act of 1939, and that nothing in the senior note indenture shall be deemed to prohibit the senior note trustee or us from making any application permitted pursuant to such section. The senior note trustee is also a depositary of ours and certain of our affiliates and has in the past made, and may in the future make, periodic loans to us and certain of our affiliates.

Governing Law

The senior note indenture and the Exchange Notes will be governed by New York law.

Book-Entry

The certificates representing the Exchange Notes, or Global Certificates, will be issued in fully registered form, without coupons. The Exchange Notes will be deposited with, or on behalf of, DTC, and registered in the name of Cede & Co., as DTC s nominee in the form of one or more Global Certificates or will remain in the

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custody of the trustee pursuant to a FAST Balance Certificate Agreement between DTC and the trustee. Upon the issuance of the Global Certificate, DTC or its nominee will credit, on its internal system, the principal amount of the individual beneficial interests represented by such Global Certificate to the accounts of persons who have accounts with such depositary. Ownership of beneficial interests in a Global Certificate will be limited to persons who have accounts with DTC, or participants, or persons who hold interests through participants. Ownership of beneficial interests in a Global Certificate will be shown on, and the transfer of that ownership will be effected only through, records maintained by DTC or its nominee (with respect to interests of participants) and the records of participants (with respect to interests of persons other than participants).

So long as DTC or its nominee is the registered owner or holder of a Global Certificate, DTC or such nominee, as the case may be, will be considered the sole owner or holder of the Exchange Notes represented by such Global Certificate for all purposes under the senior note indenture and the Exchange Notes. No beneficial owner of an interest in a Global Certificate will be able to transfer the interest except in accordance with DTC s applicable procedures, in addition to those provided for under the senior note indenture.

Payments of the principal of, and interest on, a Global Certificate will be made to DTC or its nominee, as the case may be, as the registered owner thereof. Neither we, the senior note trustee nor any paying agent will have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in a Global Certificate or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests. DTC or its nominee, upon receipt of any payment of principal or interest in respect of a Global Certificate, will credit participants accounts with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Certificate as shown on the records of DTC or its nominee. We also expect that payments by participants to owners of beneficial interests in such Global Certificate held through such participants will be governed by standing instructions and customary practices, as is now the case with securities held for the accounts of customers registered in the names of nominees for such customers. Such payments will be the responsibility of such participants and neither we, the senior note trustee nor any paying agent will have any responsibility therefor.

Transfers between participants in DTC will be effected in the ordinary way in accordance with DTC rules. If a holder requires physical delivery of a certificated Exchange Note for any reason, including to sell Exchange Notes to persons in jurisdictions which require such delivery of such Exchange Notes or to pledge such Exchange Notes, such holder must transfer its interest in a Global Certificate in accordance with DTC s applicable procedures, or the procedures set forth in the senior note indenture.

DTC will take any action permitted to be taken by a holder of Exchange Notes (including the presentation of Exchange Notes for exchange as described below) only at the direction of one or more participants to whose account the DTC interests in a Global Certificate is credited and only in respect of such portion of the aggregate principal amount of the Exchange Notes as to which such participant or participants has or have given such direction. However, if there is an Event of Default under the Exchange Notes, DTC will exchange a Global Certificate for certificated Exchange Notes, which it will distribute to its participants.

DTC has advised us that it is a limited purpose trust company organized under the laws of the State of New York, a member of the Federal Reserve System, a clearing corporation within the meaning of the Uniform Commercial Code and a Clearing Agency registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for its participants and facilitate the clearance and settlement of securities transactions between participants through electronic book entry changes in accounts of its participants, thereby eliminating the need for physical movement of certificates. Participants include securities brokers and dealers, banks, trust companies and clearing corporations and may include certain other organizations. Indirect access to the DTC system is available to others such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a participant, either directly or indirectly (indirect participants). The rules applicable to DTC and its participants are on file with the SEC.

Although DTC is expected to follow the foregoing procedures in order to facilitate transfers of interests in the Exchange Notes represented by a Global Certificate among its participants, it is under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. Neither we nor the senior note trustee will have any responsibility for the performance by DTC or its respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

If DTC is at any time unwilling or unable to continue as a depositary for a Global Certificate and a successor depositary is not appointed by us within 90 days, we will issue certificated Exchange Notes in exchange for a Global Certificate.

All payments of principal and interest will be made by us in immediately available funds.

Secondary trading in long-term bonds and notes of corporate issuers is generally settled in clearing-house or next-day funds. In contrast, beneficial interests in the Exchange Notes that are not certificated Exchange Notes will trade in DTC s Same-Day Funds Settlement System until maturity. Therefore, the secondary market trading activity in such interests will settle in immediately available funds. No assurance can be given as to the effect, if any, of settlement in immediately available funds on trading activity in the Exchange Notes.

The information under this caption Book-Entry concerning DTC and DTC s book-entry system has been obtained from information provided by DTC. We have provided the foregoing descriptions of the operations and procedures of DTC solely as a matter of convenience. The operations and procedures are solely within the control of DTC and are subject to change by DTC from time to time. You are urged to contact DTC or its participants directly to discuss these matters.

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THE EXCHANGE OFFER

General

We are offering to exchange up to $250,000,000 in aggregate principal amount of 2017 Exchange Notes for the same aggregate principal amount of 2017 Original Notes and up to $300,000,000 in aggregate principal amount of 2037 Exchange Notes for the same aggregate principal amount of 2037 Original Notes, properly tendered and not validly withdrawn before the expiration date. Unlike the Original Notes, the Exchange Notes will be registered under the Securities Act. We are making this exchange offer for all of the Original Notes. Your participation in this exchange offer is voluntary, and you should carefully consider whether to accept this offer.

On the date of this prospectus, $550,000,000 in aggregate principal amount of Original Notes is outstanding. Our obligations to accept Original Notes for Exchange Notes pursuant to this exchange offer are limited by the conditions listed under Conditions to the Exchange Offer below. We currently expect that each of the conditions will be satisfied and that no waivers will be necessary.

Purpose of the Exchange Offer

On May 21, 2007, we issued and sold $250,000,000 in aggregate principal amount of 5.65% Senior Notes due 2017 and $300,000,000 in aggregate principal amount of $6.15% Senior Notes due 2037 in a transaction exempt from the registration requirements of the Securities Act. The initial purchasers of the Original Notes subsequently resold the Original Notes to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to non-US persons pursuant to Regulation S of the Securities Act.

Because the transactions were exempt from registration under the Securities Act, a holder may reoffer, resell or otherwise transfer Original Notes only if the Original Notes are registered under the Securities Act or if an applicable exemption from the registration and prospectus delivery requirements of the Securities Act is available.

In connection with the issuance and sale of the Original Notes, we entered into a registration rights agreement with the initial purchasers of the Original Notes, which requires us to (1) prepare and, as soon as practicable following the date of original issuance of the Original Notes (May 21, 2007), file with the SEC an exchange offer registration statement with respect to this exchange offer and the issuance and delivery to the holders, in exchange for the Original Notes, of a like principal amount of Exchange Notes, (2) use our reasonable best efforts to cause the exchange offer registration statement to be declared effective under the Securities Act not later than 180 calendar days following the date of original issuance of the Original Notes, (3) use our reasonable best efforts to keep the exchange offer registration statement effective until the closing of this exchange offer and (4) use our reasonable best efforts to cause this exchange offer to be consummated within 210 calendar days following the date of original issuance of the Original Notes. In addition, there are circumstances under which we are required to file a shelf registration statement with respect to resales of the Original Notes. The registration rights agreement also provides that if neither this exchange offer is consummated nor a shelf registration statement is declared effective within 210 calendar days of the date of original issuance of the Original Notes, the annual interest rate borne by the Original Notes will be increased by 0.25% per annum commencing on the date that is 210 days after the date of original issuance of the Original Notes until this exchange offer is consummated or the shelf registration statement is declared effective. We have filed a copy of the registration rights agreement as an exhibit to the registration statement on Form S-4 with respect to the Exchange Notes offered by this prospectus.

We are making this exchange offer to satisfy our obligations under the registration rights agreement. Holders of Original Notes who do not tender their Original Notes or whose Original Notes are tendered but not accepted will have to rely on an applicable exemption from registration requirements under the Securities Act and applicable state securities laws in order to sell their Original Notes.

The Exchange Notes will be issued in a like principal amount and will be identical in all material respects to the Original Notes, except that the Exchange Notes will be registered under the Securities Act, will be issued without a restrictive legend, will bear different CUSIP numbers and will not be entitled to the rights of holders of Original Notes under the registration rights agreement, including additional interest. Consequently, the Exchange Notes, unlike the Original Notes, may be resold by a holder without any restrictions on their transfer under the Securities Act.

Resale of Exchange Notes

We have not requested, and do not intend to request, an interpretation by the staff of the SEC as to whether the Exchange Notes issued pursuant to this exchange offer in exchange for the Original Notes may be offered for sale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. Instead, based on existing interpretations of the Securities Act by the staff of the SEC set forth in several no-action letters to third parties, and subject to the immediately following sentence, we believe that the Exchange Notes to be issued pursuant to this exchange offer in exchange for Original Notes may be offered for resale, resold and otherwise transferred by any holder of Exchange Notes (other than holders who are broker-dealers) without further compliance with the registration and prospectus delivery requirements of the Securities Act. However, any purchaser of the Original Notes who is an affiliate of ours or who intends to participate in this exchange offer for the purpose of distributing the Exchange Notes, or any broker-dealer who purchased the Original Notes from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act, (1) will not be able to rely on the interpretations of the staff of the SEC set forth in the above-mentioned no-action letters, (2) will not be entitled to tender its Original Notes in this exchange offer and (3) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the Original Notes unless such sale or transfer is made pursuant to an exemption from such requirements. Because the SEC has not considered our exchange offer in the context of a no-action letter, we cannot assure you that the staff would make a similar determination with respect to this exchange offer.

If you participate in this exchange offer, you must represent to us, among other things, that:

(1) any Exchange Notes you receive will be acquired in the ordinary course of business;

(2) you have no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the Exchange Notes;

(3) you are not an affiliate (as defined in Rule 405 of the Securities Act) of ours;

(4) if you are not a broker-dealer, you are not engaged in, and do not intend to engage in, the distribution (within the meaning of the Securities Act) of the Exchange Notes; and

(5) if you are a participating broker-dealer that will receive Exchange Notes for your own account in exchange for Original Notes that were acquired as a result of market-making activities or other trading activities, you acknowledge that you will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of such Exchange Notes.

Any holder that is not able to make these representations or certain similar representations will not be entitled to participate in this exchange offer and, therefore, will not be permitted to exchange its Original Notes for Exchange Notes.

This exchange offer is not being made to, nor will we accept tenders for exchange from, holders of Original Notes in any jurisdiction in which this exchange offer or the acceptance thereof would not be in compliance with the securities or blue sky laws of such jurisdiction.

Terms of the Exchange Offer

Upon the terms and subject to the conditions set forth in this prospectus and in the letter of transmittal, we will accept for exchange any Original Notes validly tendered and not withdrawn before expiration of this exchange offer. The date of acceptance for exchange of the Original Notes and completion of this exchange offer is the exchange date, which will be the first business day following the expiration date unless we extend the date as described in this prospectus. The Original Notes may be tendered only in denominations of $2,000 and integral multiples of $1,000 in excess thereof. We will issue $1,000 principal amount of Exchange Notes in exchange for each $1,000 principal amount of Original Notes surrendered under this exchange offer. The Exchange Notes will be delivered on the earliest practicable date following the exchange date.

The form and terms of the Exchange Notes will be substantially identical to the form and terms of the Original Notes, except the Exchange Notes:

(1) will be registered under the Securities Act;

(2) will not bear legends restricting their transfer;

(3) will bear different CUSIP numbers; and

(4) will not be entitled to the rights of holders of Original Notes under the registration rights agreement, including additional interest.

The Exchange Notes will evidence the same debt as the Original Notes. The Exchange Notes will be issued under and entitled to the benefits of the senior note indenture, as described below, under which the Original Notes were issued.

This exchange offer is not conditioned upon any minimum aggregate principal amount of Original Notes being tendered for exchange. This prospectus and the letter of transmittal are being sent to all registered holders of outstanding Original Notes. There will be no fixed record date for determining registered holders of Original Notes entitled to participate in this exchange offer.

We intend to conduct this exchange offer in accordance with the applicable requirements of the Securities Act, Exchange Act and rules and regulations of the SEC. Original Notes that are not exchanged in this exchange offer will remain outstanding and continue to accrue interest and will be entitled to the rights and benefits their holders have under the senior note indenture relating to the senior notes. Holders of Original Notes do not have any appraisal or dissenters rights under the senior note indenture in connection with this exchange offer.

We will be deemed to have accepted for exchange validly tendered Original Notes when we have given oral (promptly confirmed in writing) or written notice of the acceptance to the exchange agent. The exchange agent will act as agent for the holders of Original Notes who surrender them in this exchange offer for the purposes of receiving Exchange Notes from us and delivering Exchange Notes to their holders. The exchange agent will make the exchange as promptly as practicable on or after the date of acceptance for exchange of Original Notes. We expressly reserve the right to amend or terminate this exchange offer and not to accept for exchange any Original Notes not previously accepted for exchange, upon the occurrence of any of the conditions specified under Conditions to the Exchange Offer below.

Holders who tender Original Notes in this exchange offer will not be required to pay brokerage commissions or fees or, subject to the instructions in the letter of transmittal, transfer taxes with respect to the exchange of Original Notes. We will pay all charges and expenses, other than applicable taxes described below, in connection with this exchange offer. It is important that you read Solicitation of Tenders; Fees and Expenses and Transfer Taxes below for more details regarding fees and expenses incurred in this exchange offer.

Any Original Notes not tendered for exchange will be entitled to the benefits of the senior note indenture. If any tendered Original Notes are not accepted for exchange because of an invalid tender or the occurrence of certain other events, such Original Notes will be returned, without expense, to the tendering holder thereof as promptly as practicable after the expiration date.

Expiration Date; Extension; Termination; Amendment

This exchange offer will expire at 5:00 p.m., New York City time, on December 13, 2007, unless we have extended the period of time that this exchange offer is open. The expiration date will be at least 20 business days after the date we mail notice of this exchange offer to DTC.

We reserve the right to extend the period of time that this exchange offer is open, and delay acceptance for exchange of any Original Notes, by giving oral (promptly confirmed in writing) or written notice to the exchange agent and by timely public announcement no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled expiration date. During any extension, all Original Notes previously tendered will remain subject to this exchange offer unless validly withdrawn.

We also reserve the right, in our sole discretion, to:

(1) end or amend this exchange offer and not to accept for exchange any Original Notes not previously accepted for exchange upon the occurrence of any of the events specified under Conditions to the Exchange Offer below that have not been waived by us; and

(2) amend the terms of this exchange offer in any manner.

If any termination or amendment occurs, we will notify the exchange agent and will either issue a press release or give oral or written notice to holders of Original Notes as promptly as practicable.

Exchange Notes will only be issued after the exchange agent timely receives (1) a properly completed and duly executed letter of transmittal (or facsimile thereof or an agent s message (as hereinafter defined) in lieu thereof) and (2) all other required documents. However, we reserve the absolute right to waive any defects or irregularities in the tender or conditions of this exchange offer.

Original Notes that are not accepted for exchange, and those Original Notes submitted for a greater principal amount than the tendering holder desires to exchange, will be returned, without expense, to the tendering holder thereof as promptly as practicable after the expiration date.

Procedures For Tendering Original Notes

Valid Tender

Except as set forth below, in order for Original Notes to be validly tendered pursuant to this exchange offer, either (1) (a) a properly completed and duly executed letter of transmittal (or facsimile thereof) or an electronic message agreeing to be bound by the letter of transmittal properly transmitted through DTC s Automated Tender Offer Program, or ATOP, for a book-entry transfer, with any required signature guarantees and any other required documents, must be received by the exchange agent at the address or the facsimile number set forth under Exchange Agent below on or prior to the expiration date and (b) tendered Original Notes must be received by the exchange agent, or such Original Notes must be tendered pursuant to the procedures for book-entry transfer set forth below and a book-entry confirmation must be received by the exchange agent, in each case on or prior to the expiration date, or (2) the guaranteed delivery procedures set forth below must be complied with. To receive confirmation of valid tender of Original Notes, a holder should contact the exchange agent at the telephone number listed under Exchange Agent below.

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If less than all of the Original Notes are tendered, a tendering holder should fill in the amount of Original Notes being tendered in the appropriate box on the letter of transmittal. The entire amount of Original Notes delivered to the exchange agent will be deemed to have been tendered unless otherwise indicated.

If any letter of transmittal, endorsement, note power, power of attorney or any other document required by the letter of transmittal is signed by a trustee, executor, administrator, guardian, attorney-in fact, officer of a corporation or other person acting in a fiduciary or representative capacity, such person should so indicate when signing. Unless waived by us, evidence satisfactory to us of such person s authority to so act also must be submitted.

Any beneficial owner of Original Notes that are held by or registered in the name of a broker, dealer, commercial bank, trust company or other nominee is urged to contact such entity promptly if such beneficial holder wishes to participate in this exchange offer.

The method of delivering Original Notes, the letter of transmittal and all other required documents is at the option and sole risk of the tendering holder. Delivery will be deemed made only when actually received by the exchange agent. Instead of delivery by mail, it is recommended that holders use an overnight or hand delivery service. In all cases, sufficient time should be allowed to assure timely delivery and proper insurance should be obtained. No Original Note, letter of transmittal or other required document should be sent to us. Holders may request their respective brokers, dealers, commercial banks, trust companies or other nominees to effect these transactions for them.

Book-Entry Transfer

The exchange agent has established an account with respect to the Original Notes at DTC for purposes of this exchange offer. The exchange agent and DTC have confirmed that any financial institution that is a participant in DTC may utilize DTC s ATOP procedures to tender Original Notes. Any participant in DTC may make book-entry delivery of Original Notes by causing DTC to transfer the Original Notes into the exchange agent s account in accordance with DTC s ATOP procedures for transfer.

However, the exchange for the Original Notes so tendered will be made only after a book-entry confirmation of such book-entry transfer of Original Notes into the exchange agent s account and timely receipt by the exchange agent of an agent s message and any other documents required by the letter of transmittal. The term agent s message means a message, transmitted by DTC and received by the exchange agent and forming part of a book-entry confirmation, which states that DTC has received an express acknowledgment from a participant tendering Original Notes that are the subject of the book-entry confirmation that the participant has received and agrees to be bound by the terms of the letter of transmittal, and that we may enforce that agreement against the participant.

Delivery of documents to DTC does not constitute delivery to the exchange agent.

Signature Guarantees

Certificates for Original Notes need not be endorsed and signature guarantees on a letter of transmittal or a notice of withdrawal, as the case may be, are unnecessary unless (1) a certificate for Original Notes is registered in a name other than that of the person surrendering the certificate or (2) a registered holder completes the box entitled Special Issuance Instructions or Special Delivery Instructions in the letter of transmittal. In the case of (1) or (2) above, such certificates for Original Notes must be duly endorsed or accompanied by a properly executed note power, with the endorsement or signature on the note power and on the letter of transmittal or the notice of withdrawal, as the case may be, guaranteed by a firm or other entity identified in Rule 17Ad-15 under the Exchange Act as an eligible guarantor institution, including (as such terms are defined therein) (i) a bank, (ii) a broker, dealer, municipal securities broker or dealer or government securities broker or dealer, (iii) a credit

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union, (iv) a national securities exchange, registered securities association or clearing agency or (v) a savings association that is a participant in a Securities Transfer Association (each an Eligible Institution), unless an Original Note is surrendered for the account of an Eligible Institution. See Instruction 2 to the letter of transmittal.

Guaranteed Delivery

If a holder desires to tender Original Notes pursuant to this exchange offer and the certificates for such Original Notes are not immediately available or time will not permit all required documents to reach the exchange agent before the expiration date, or the procedures for book-entry transfer cannot be completed on a timely basis, such Original Notes may nevertheless be tendered, provided that all of the following guaranteed delivery procedures are complied with:

(1) such tenders are made by or through an Eligible Institution;

(2) prior to the expiration date, the exchange agent receives from the Eligible Institution a properly completed and duly executed notice of guaranteed delivery, substantially in the form accompanying the letter of transmittal, or an electronic message through ATOP with respect to guaranteed delivery for book-entry transfers, setting forth the name and address of the holder of Original Notes and the amount of Original Notes tendered, stating that the tender is being made thereby and guaranteeing that within three New York Stock Exchange trading days after the date of execution of the notice of guaranteed delivery, or transmission of such electronic message through ATOP for book-entry transfers, the certificates for all physically tendered Original Notes, in proper form for transfer, or a book-entry confirmation, as the case may be, and any other documents required by the letter of transmittal will be deposited by the Eligible Institution with the exchange agent;

(3) the certificates (or book-entry confirmation) representing all tendered Original Notes, in proper form for transfer, together with a properly completed and duly executed letter of transmittal with any required signature guarantees (or a facsimile thereof), or a properly transmitted electronic message through ATOP in the case of book-entry transfers, and any other documents required by the letter of transmittal, are received by the exchange agent within three New York Stock Exchange trading days after the date of execution of the notice of guaranteed delivery or transmission of such electronic message through ATOP with respect to guaranteed delivery for book-entry transfers.

Determination of Validity

We will determine in our sole discretion all questions as to the validity, form, eligibility, including time of receipt, acceptance and withdrawal of tendered Original Notes. Our determination will be final and binding. We reserve the absolute right to reject any Original Notes not properly tendered or any Original Notes the acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defects, irregularities or conditions of tender as to particular Original Notes. Our interpretation of the terms and conditions of this exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties.

Unless waived, any defects or irregularities in connection with tenders of Original Notes must be cured within the time that we determine. Although we intend to notify holders of defects or irregularities with respect to tenders of Original Notes, neither we, the exchange agent nor any other person will incur any liability for failure to give notification. Tenders of Original Notes will not be deemed made until those defects or irregularities have been cured or waived. Any Original Notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned by the exchange agent without cost to the tendering holder, unless otherwise provided in the letter of transmittal, as soon as practicable after withdrawal, rejection of tender or termination of this exchange offer.

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Withdrawal Rights

You may withdraw your tender of Original Notes at any time before 5:00 p.m., New York City time, on the expiration date.

For a withdrawal to be effective, the exchange agent must receive a computer generated notice of withdrawal, transmitted by DTC on behalf of the holder in accordance with the standard operating procedure of DTC or a written notice of withdrawal, sent by facsimile transmission, receipt confirmed by telephone, or letter, before the expiration date.

Any notice of withdrawal must:

(1) specify the name of the person that tendered the Original Notes to be withdrawn;

(2) identify the Original Notes to be withdrawn, including the certificate number or numbers (if in certificated form) and principal amount of such Original Notes;

(3) include a statement that the holder is withdrawing its election to have the Original Notes exchanged;

(4) be signed by the holder in the same manner as the original signature on the letter of transmittal by which the Original Notes were tendered or as otherwise described above, including any required signature guarantees, or be accompanied by documents of transfer sufficient to have the senior note trustee under the senior note indenture register the transfer of the Original Notes into the name of the person withdrawing the tender; and

(5) specify the name in which any of the Original Notes are to be registered, if different from that of the person that tendered the Original Notes.

The exchange agent will return the properly withdrawn Original Notes promptly following receipt of a notice of withdrawal. If Original Notes have been tendered pursuant to the procedure for book-entry transfer, any notice of withdrawal must specify the name and number of the account at DTC to be credited with the withdrawn Original Notes or otherwise comply with DTC s procedures.

Any Original Notes withdrawn will not have been validly tendered for exchange for purposes of this exchange offer. Any Original Notes that have been tendered for exchange but which are not exchanged for any reason will be returned to the holder without cost to the holder as soon as practicable after withdrawal, rejection of tender or termination of this exchange offer. In the case of Original Notes tendered by book-entry transfer into the exchange agent s account at DTC pursuant to its book-entry transfer procedures, the Original Notes will be credited to an account with DTC specified by the holder, as soon as practicable after withdrawal, rejection of tender or termination of this exchange offer. Properly withdrawn Original Notes may be retendered by following one of the procedures described under Procedures For Tendering Original Notes above at any time on or before the expiration date.

Acceptance of Original Notes for Exchange; Delivery of Exchange Notes

Upon satisfaction or waiver of all of the conditions to this exchange offer, we will accept, promptly after the exchange date, all Original Notes validly tendered and will issue the Exchange Notes promptly after the acceptance. Please refer to the section in this prospectus entitled Conditions to the Exchange Offer below. For purposes of this exchange offer, we will be deemed to have accepted validly tendered Original Notes for exchange when we give notice of acceptance to the exchange agent.

For each Original Note accepted for exchange, the holder of the Original Note will receive an Exchange Note having a principal amount at maturity equal to that of the surrendered Original Note.

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In all cases, delivery of Exchange Notes in exchange for Original Notes tendered and accepted for exchange pursuant to this exchange offer will be made only after timely receipt by the exchange agent of:

(1) Original Notes or a book-entry confirmation of a book-entry transfer of Original Notes into the exchange agent s account at DTC;

(2) a properly completed and duly executed letter of transmittal or an electronic message agreeing to be bound by the letter of transmittal properly transmitted through ATOP with any required signature guarantees; and

(3) any other documents required by the letter of transmittal.

Accordingly, the delivery of Exchange Notes might not be made to all tendering holders at the same time and will depend upon when Original Notes, book-entry confirmations with respect to Original Notes and other required documents are received by the exchange agent.

Conditions to the Exchange Offer

We are required to accept for exchange, and to issue Exchange Notes in exchange for, any Original Notes duly tendered and not validly withdrawn pursuant to this exchange offer and in accordance with the terms of this prospectus and the accompanying letter of transmittal.

We will not be required to accept for exchange, or to issue Exchange Notes in exchange for, any Original Notes, if:

(1) this exchange offer, or the making of any exchange by a holder, would violate applicable law or any applicable interpretation of the staff of the SEC;

(2) the Original Notes are not tendered in accordance with the terms of this exchange offer;

(3) each holder of Original Notes exchanged in this exchange offer has not represented that all Exchange Notes to be received by it shall be acquired in the ordinary course of its business, that is not an affiliate of ours and that at the time of the consummation of this exchange offer it shall have no arrangement or understanding with any person to participate in any distribution (within the meaning of the Securities Act) of the Exchange Notes and shall not have made such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to render the use of the registration statement of which this prospectus is a part available; or

(4) any action or proceeding has been instituted or threatened in any court or by or before any governmental agency with respect to this exchange offer that, in our judgment, would reasonably be expected to impair our ability to proceed with this exchange offer.

In addition, we will not be obligated to accept for exchange the Original Notes of any holder who has not made to us the representations described under Resale of Exchange Notes above and Plan of Distribution below.

In addition, we will not accept for exchange any Original Notes tendered, and no Exchange Notes will be issued in exchange for those Original Notes, if at such time any stop order is threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the senior note indenture under the Trust Indenture Act of 1939. In any of those events we are required to use reasonable efforts to obtain the withdrawal of any stop order at the earliest possible time.

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Exchange Agent

We have appointed The Bank of New York Trust Company, N.A. as the exchange agent for this exchange offer. You should direct questions and requests for assistance, in each case, with respect to exchange offer procedures, requests for additional copies of this prospectus or of the letter of transmittal, requests for the notice of guaranteed delivery with respect to the exchange of the Original Notes, as well as all executed letters of transmittal, to the exchange agent at the addresses listed below:

By Hand or Overnight Delivery:	*By Registered or Certified Mail:*	*By Facsimile Transmission:*
The Bank of New York	The Bank of New York	(Eligible Institutions Only)
101 Barclay Street	101 Barclay Street, Floor 7 East	(212) 298-1915
Corporate Trust Services Window	New York, New York 10286	
Ground Level	Attention: David Mauer Corp.	*To Confirm by Telephone or*
New York, New York 10286	Trust Ops-Reorganization Unit	*for Information:*
Attention: David Mauer Corp.		(212) 815-3687
Trust Ops-Reorganization		
Unit/Floor 7 East		

Delivery to an address other than as listed above, or transmissions to a facsimile number other than as listed above, will not constitute a valid delivery.

The Bank of New York Trust Company, N.A. is the successor senior note trustee under the senior note indenture governing the Original Notes and Exchange Notes.

Solicitation of Tenders; Fees and Expenses

We will pay the expenses of soliciting tenders. The principal solicitation is being made by mail; however, additional solicitation may be made by telecopier, telephone or in person by officers and employees of ours and of our affiliates.

We have not retained any dealer-manager in connection with this exchange offer and will not make any payments to brokers, dealers or others soliciting acceptances of this exchange offer. However, we will pay the exchange agent reasonable and customary fees for its services and will reimburse it for its reasonable out-of-pocket expenses in connection with this exchange offer.

We will pay the estimated cash expenses to be incurred in connection with this exchange offer, including the following:

(1) fees and expenses of the exchange agent and senior note trustee;

(2) SEC registration fees;

(3) accounting and legal fees, including fees of one counsel for the holders of the Original Notes; and

(4) printing and mailing expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of Original Notes under this exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if:

(1) certificates representing Original Notes for principal amounts not tendered or accepted for exchange are to be delivered to, or are to be issued in the name of, any person other than the registered holder of Original Notes tendered;

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(2) Exchange Notes are to be delivered to, or issued in the name of, any person other than the registered holder of the Original Notes;

(3) tendered Original Notes are registered in the name of any person other than the person signing the letter of transmittal; or

(4) a transfer tax is imposed for any reason other than the exchange of Original Notes under this exchange offer.

If satisfactory evidence of payment of such transfer taxes is not submitted with the letter of transmittal, the amount of any transfer taxes will be billed to the tendering holder.

Accounting Treatment

We will record the Exchange Notes at the same carrying value as the Original Notes for which they are exchanged, which is the aggregate principal amount of the tendered Original Notes as reflected in our accounting records on the date this exchange offer is completed. Accordingly, we will not recognize any gain or loss for accounting purposes upon the exchange of Exchange Notes for Original Notes. We will amortize the expenses incurred in connection with the issuance of the Exchange Notes over the terms of the Exchange Notes.

Consequences of Failure to Exchange

If you do not exchange your Original Notes for Exchange Notes pursuant to this exchange offer, you will continue to be subject to the restrictions on transfer of the Original Notes as described in the legend on the Original Notes. In general, the Original Notes may be offered or sold only if registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws.

Your participation in this exchange offer is voluntary, and you should carefully consider whether to participate. We urge you to consult your financial and tax advisors in making a decision whether or not to tender your Original Notes. Please refer to the section in this prospectus entitled Material U.S. Federal Income Tax Consequences.

As a result of the making of, and upon acceptance for exchange of all validly tendered Original Notes pursuant to the terms of, this exchange offer, we will have fulfilled a covenant contained in the registration rights agreement. If you do not tender your Original Notes in this exchange offer, you will be entitled to all of the rights and limitations applicable to the Original Notes under the senior note indenture, except for any rights under the registration rights agreement that by their terms end or cease to have further effectiveness as a result of the making of this exchange offer, including the right to require us to register your Original Notes or pay additional interest. To the extent that Original Notes are tendered and accepted in this exchange offer, the trading market for untendered, or tendered but unaccepted, Original Notes could be adversely affected. Please refer to the section in this prospectus entitled Risk Factors If you do not properly tender your Original Notes for Exchange Notes, you will continue to hold unregistered notes that are subject to transfer restrictions.

We may in the future seek to acquire untendered Original Notes in open market or privately negotiated transactions through subsequent exchange offers or otherwise. However, we have no present plans to acquire any Original Notes that are not tendered in this exchange offer or to file a registration statement to permit resales of any untendered Original Notes.

Holders of Original Notes and of Exchange Notes that remain outstanding after consummation of this exchange offer will vote together as a single class for purposes of determining whether holders of the requisite percentage thereof have taken certain actions or exercised certain rights under the senior note indenture.

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MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

General

The following is a summary of certain material United States federal income tax consequences of the exchange of Original Notes for Exchange Notes pursuant to this exchange offer, but does not address any other aspects of United States federal income tax consequences to holders of Original Notes or Exchange Notes. This summary is based upon the Code, the Treasury Regulations promulgated or proposed thereunder, and administrative and judicial interpretations thereof, all as of the date hereof and all of which are subject to change, possibly on a retroactive basis. This summary is not binding on the Internal Revenue Service, or IRS, or on the courts, and no ruling will be sought from the IRS with respect to the statements made and the conclusions reached in this summary. There can be no assurance that the IRS will agree with such statements and conclusions.

This summary is limited to the material United States federal income tax consequences relevant to those persons who are the original beneficial owners of Original Notes, who exchange Original Notes for Exchange Notes in this exchange offer and who hold Original Notes as capital assets within the meaning of Section 1221 of the Code, which we refer to as Holders. This summary does not address specific tax consequences that may be relevant to particular persons (including banks, financial institutions, broker-dealers, insurance companies, real estate investment trusts, regulated investment companies, partnerships or other pass-through entities, expatriates, tax-exempt organizations and persons that have a functional currency other than the United States Dollar or persons in special situations, such as those who have elected to mark securities to market or those who hold the notes as part of a straddle, hedge, conversion transaction or other integrated investment). In addition, this summary does not address United States federal alternative minimum, estate and gift tax consequences, consequences under the tax laws of any state, local or foreign jurisdiction, or consequences under any United States federal tax laws other than income tax law.

If a partnership or other entity taxable as a partnership holds Original Notes, the tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership holding the notes, you should consult your tax advisor regarding the tax consequences of the exchange of Original Notes for Exchange Notes pursuant to this exchange offer.

This summary is for general information only. Persons considering the exchange of Original Notes for Exchange Notes are urged to consult their own tax advisors concerning the United States federal income tax consequences to them of exchanging the notes, as well as the application of state, local and foreign tax laws and United States federal tax laws other than income tax law.

Exchange of an Original Note for an Exchange Note Pursuant to this Exchange Offer

The exchange of Original Notes for Exchange Notes in the exchange offer described herein will not constitute a significant modification of the terms of the Original Notes and thus will not constitute a taxable exchange for United States federal income tax purposes. Rather, the Exchange Notes will be treated as a continuation of the Original Notes. Consequently, a Holder will not recognize gain or loss upon receipt of the Exchange Notes in exchange for the Original Notes in the exchange offer, the Holder s basis in the Exchange Notes received in the exchange offer will be the same as its basis in the Original Notes immediately before the exchange, and the Holder s holding period in the Exchange Notes will include its holding period in the Original Notes.

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PLAN OF DISTRIBUTION

As discussed under The Exchange Offer in this prospectus, based on interpretations by the staff of the SEC set forth in no-action letters issued to other companies, we believe that a holder, other than a person that is an affiliate of ours within the meaning of Rule 405 under the Securities Act or a broker-dealer registered under the Exchange Act that purchases Original Certificates or Exchange Notes from us to resell pursuant to Rule 144A under the Securities Act or any other exemption, that acquires the Exchange Notes in the ordinary course of business and that is not participating in, does not intend to participate in, and has no arrangement or understanding with any person to participate in, the distribution of the Original Certificates or Exchange Notes will be allowed to resell the Exchange Notes to the public without further registration under the Securities Act and without delivering to the purchasers of the Exchange Notes a prospectus that satisfies the requirements of Section 10 of the Securities Act. However, if any holder acquires Exchange Notes in this exchange offer for the purpose of distributing or participating in a distribution of the Exchange Notes, such holder cannot rely on the position of the staff enunciated in Morgan Stanley & Co., Inc. (available June 5, 1991) and Exxon Capital Holdings Corp. (available May 13, 1988), as interpreted in the SEC s letter to Shearman & Sterling dated July 2, 1993, or similar no-action or interpretive letters and must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction, and such secondary resale transaction must be covered by an effective registration statement containing the selling security holder information required by Item 507 or 508, as applicable, of Regulation S-K if the resales are of Exchange Notes obtained by such holder in exchange for Original Certificates acquired by such holder directly from us or an affiliate thereof, unless an exemption from registration is otherwise available.

As contemplated by the above no-action letters and the registration rights agreement, each holder accepting this exchange offer is required to represent to us in the letter of transmittal that:

(1) any Exchange Notes it receives will be acquired in the ordinary course of business;

(2) it has no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the Exchange Notes;

(3) it is not an affiliate of ours as defined in Rule 405 of the Securities Act;

(4) if it is not a broker-dealer, it is not engaged in, and does not intend to engage in, the distribution (within the meaning of the Securities Act) of the Exchange Notes within the meaning of the Securities Act; and

(5) if it is a participating broker-dealer that it will receive Exchange Notes for its own account in exchange for Original Notes that were acquired as a result of market-making activities or other trading activities, and acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of such Exchange Notes.

This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Notes received in exchange for Original Notes where such Original Notes were acquired as a result of market-making activities or other trading activities. We have agreed that, for a period ending on the sooner of 90 days after the consummation of the exchange offer and the date on which all participating broker-dealers have sold all Exchange Notes held by them, unless such period is extended pursuant to the registration rights agreement, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale. In addition, dealers effecting transactions in Exchange Notes may be required to deliver a prospectus.

We will not receive any proceeds from any sale of Exchange Notes by broker-dealers. Exchange Notes received by broker-dealers for their own account pursuant to this exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Notes or a combination of such methods of resale, at market prices prevailing at the

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time of resale, at prices related to such prevailing market prices or negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such Exchange Notes. Any broker-dealer that resells Exchange Notes that were received by it for its own account pursuant to this exchange offer and any broker or dealer that participates in a distribution of such Exchange Notes may be deemed to be an underwriter within the meaning of the Securities Act, and any profit on any such resale of Exchange Notes and any commission or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act.

LEGAL MATTERS

Certain legal matters with respect to the Exchange Notes will be passed upon for us by Akin Gump Strauss Hauer & Feld LLP, New York, New York and Thelen Reid Brown Raysman & Steiner LLP, Florham Park, New Jersey. Thelen Reid Brown Raysman & Steiner LLP, New York, New York acted as counsel to the initial purchasers in connection with the issuance and sale of the Original Notes.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The financial statements as of December 31, 2006 and 2005 and for each of the three years in the period ended December 31, 2006 included in this prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

With respect to the unaudited financial information of Jersey Central Power & Light Company for the three-month and nine-month periods ended September 30, 2007 and 2006 included in this prospectus, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated October 31, 2007 appearing herein states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Securities Act.

INDEX TO FINANCIAL STATEMENTS

* Notes to the Consolidated Financial Statements for the three and nine-months ended September 30, 2007 and 2006 present combined information for FirstEnergy Corp., Jersey Central Power & Light Company and certain of FirstEnergy s other registrant subsidiaries. Information presented herein as it relates to Jersey Central Power & Light Company is an integral part of the Consolidated Financial Statements.

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Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of Directors of

Jersey Central Power & Light Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder s equity, preferred stock and cash flows present fairly, in all material respects, the financial position of Jersey Central Power & Light Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The Supplemental Consolidated Statements of Taxes is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for defined benefit pension and other post-retirement benefit plans as of December 31, 2006.

PricewaterhouseCoopers LLP

Cleveland, Ohio

February 27, 2007

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2006	2005	2004
		(In thousands)	
REVENUES (Note 2(H)):			
Electric sales	$ 2,617,390	$ 2,550,208	$ 2,157,532
Excise tax collections	50,255	52,026	49,455
Total Revenues	2,667,645	2,602,234	2,206,987
EXPENSES:			
Purchased power (Note 2(H))	1,521,329	1,429,998	1,166,430
Other operating costs (Note 2(H))	320,847	375,502	350,709
Provision for depreciation	83,172	80,013	75,163
Amortization of regulatory assets	274,704	292,668	278,559
Deferral of new regulatory assets		(28,862)	
General taxes	63,925	64,538	62,792
Total expenses	2,263,977	2,213,857	1,933,653
OPERATING INCOME	403,668	388,377	273,334
OTHER INCOME (EXPENSE):			
Miscellaneous income	13,323	10,084	13,449
Interest expense	(83,411)	(81,428)	(82,567)
Capitalized interest	3,758	1,740	615
Total other expense	(66,330)	(69,604)	(68,503)
INCOME BEFORE INCOME TAXES	337,338	318,773	204,831
INCOME TAXES	146,731	135,846	97,205
NET INCOME	190,607	182,927	107,626
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,018	500	500
EARNINGS ON COMMON STOCK	$ 189,589	$ 182,427	$ 107,126

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

As of December 31,	2006	2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 41	$ 102
Receivables		
Customers (less accumulated provisions of $3,524,000 and $3,830,000, respectively, for uncollectible accounts)	254,046	258,077
Associated companies	11,574	203
Other (less accumulated provision of $204,000 in 2005, for uncollectible accounts)	40,023	41,456
Notes receivable associated companies	24,456	18,419
Materials and supplies, at average cost	2,043	2,104
Prepaid taxes	13,333	10,137
Other	18,076	6,928
	363,592	337,426
UTILITY PLANT:		
In service	4,029,070	3,902,684
Less Accumulated provision for depreciation	1,473,159	1,445,718
	2,555,911	2,456,966
Construction work in progress	78,728	98,720
	2,634,639	2,555,686
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	171,045	164,203
Nuclear plant decommissioning trusts	164,108	145,975
Other	2,047	2,580
	337,200	312,758
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	2,152,332	2,226,591
Goodwill	1,962,361	1,985,858
Prepaid pension costs	14,660	148,054
Other	17,781	17,733
	4,147,134	4,378,236
	$ 7,482,565	$ 7,584,106
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 32,683	$ 207,231
Short-term borrowings		
Associated companies	186,540	181,346
Accounts payable		
Associated companies	80,426	37,955
Other	160,359	149,501
Accrued taxes	1,451	54,356
Accrued interest	14,458	19,916
Cash collateral from suppliers	32,300	141,225

Other	96,150	86,884
	604,367	878,414
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder s equity	3,159,598	3,210,763
Preferred stock		12,649
Long-term debt and other long-term obligations	1,320,341	972,061
	4,479,939	4,195,473
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	1,182,108	1,237,249
Accumulated deferred income taxes	803,944	812,034
Nuclear fuel disposal costs	183,533	175,156
Asset retirement obligations	84,446	79,527
Retirement benefits	10,207	72,454
Other	134,021	133,799
	2,398,259	2,510,219
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11)	$ 7,482,565	$ 7,584,106

The accompanying Notes to Consolidated Financial Statements are an integral part of these balance sheets.

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	Shares Outstanding 2006	Shares Outstanding 2005	Dollars in Thousands 2006	Dollars in Thousands 2005
COMMON STOCKHOLDER S EQUITY:				
Common stock, $10 par value, 16,000,000 shares authorized	15,009,335	15,371,270	$ 150,093	$ 153,713
Other paid in capital			2,908,279	3,003,190
Accumulated other comprehensive loss (Note 2(F))			(44,254)	(2,030)
Retained earnings (Note 8(A))			145,480	55,890
Total			3,159,598	3,210,763
PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION:				
Cumulative, without par value, 15,600,000 shares authorized 4.00% Series		125,000		12,649
LONG-TERM DEBT (Note 8(B)):				
First mortgage bonds				
6.850% due 2006				40,000
7.100% due 2015			12,200	12,200
7.500% due 2023			125,000	125,000
6.750% due 2025			150,000	150,000
Total			287,200	327,200
Secured notes				
6.450% due 2006				150,000
4.190% due 2006-2007			17,942	35,172
5.390% due 2007-2010			52,297	52,297
5.250% due 2007-2012			56,348	
5.810% due 2010-2013			77,075	77,075
5.410% due 2014			25,693	
5.520% due 2014-2018			49,220	
5.625% due 2016			300,000	300,000
6.160% due 2013-2017			99,517	99,517
4.800% due 2018			150,000	150,000
5.610% due 2021			51,139	
6.400% due 2036			200,000	
Total			1,079,231	864,061
Net unamortized discount on debt			(13,407)	(11,969)
Long term debt due within one year			(32,683)	(207,231)
Total long term debt			1,320,341	972,061
TOTAL CAPITALIZATION			$ 4,479,939	$ 4,195,473

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

		Common Stock			Accumulated Other	
	Comprehensive Income	Number of Shares	Par Value	Other Paid In Capital	Comprehensive Income (Loss)	Retained Earnings
				(In thousands)		
Balance, January 1, 2004		15,371,270	$ 153,713	$ 3,029,894	$ (51,765)	$ 14,337
Net income	$ 107,626					107,626
Net unrealized loss on investments	(5)				(5)	
Net unrealized gain on derivative instruments, net of $1,583,000 of income taxes	1,697				1,697	
Minimum liability for unfunded retirement benefits, net of $3,772,000 of income tax benefits	(5,461)				(5,461)	
Comprehensive income	$ 103,857					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(90,000)
Purchase accounting fair value adjustment				(15,982)		
Balance, December 31, 2004		15,371,270	153,713	3,013,912	(55,534)	31,463
Net income	$ 182,927					182,927
Net unrealized gain on derivative instruments, net of $113,000 of income taxes	163				163	
Minimum liability for unfunded retirement benefits, net of $36,838,000 of income taxes	53,341				53,341	
Comprehensive income	$ 236,431					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(158,000)
Purchase accounting fair value adjustment				(10,722)		
Balance, December 31, 2005		15,371,270	153,713	3,003,190	(2,030)	55,890
Net income	$ 190,607					190,607
Net unrealized gain on derivative instruments, net of $101,000 of income taxes	147				147	
Comprehensive income	$ 190,754					
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $42,233,000 of income tax benefits					(42,371)	
Repurchase of common stock		(361,935)	(3,620)	(73,381)		
Preferred stock redemption premium						(663)
Restricted stock units				101		
Stock based compensation				48		
Cash dividends on preferred stock						(354)
Cash dividends on common stock						(100,000)
Purchase accounting fair value adjustment				(21,679)		

Balance, December 31, 2006	15,009,335	$ 150,093	$ 2,908,279	$ (44,254)	$ 145,480

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

	Not Subject to Mandatory Redemption	
	Number of Shares	Carrying Value
	(In thousands)	
Balance, January 1, 2004	125,000	$ 12,649
Balance, December 31, 2004	125,000	12,649
Balance, December 31, 2005	125,000	12,649
Redemptions 4.00% Series	(125,000)	(12,649)
Balance, December 31, 2006		$

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2006	2005	2004
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 190,607	$ 182,927	$ 107,626
Adjustments to reconcile net income to net cash from operating activities			
Provision for depreciation	83,172	80,013	75,163
Amortization of regulatory assets	274,704	292,668	278,559
Deferral of new regulatory assets		(28,862)	
Deferred purchased power and other costs	(281,498)	(257,418)	(263,257)
Deferred income taxes and investment tax credits, net	43,896	36,125	54,887
Accrued compensation and retirement benefits	(12,670)	(10,431)	(1,972)
NUG power contract restructuring			52,800
Cash collateral from (returned to) suppliers	(109,108)	134,563	6,662
Pension trust contribution		(79,120)	(62,499)
Accrued liability from arbitration decision		16,141	
Decrease (lncrease) in operating assets			
Receivables	1,103	28,108	(13,360)
Materials and supplies	61	331	45
Prepaid taxes	5,385	15,514	14,203
Other current assets	(2,134)	(1,090)	3,667
Increase (decrease) in operating liabilities			
Accounts payable	53,330	42,118	(2,887)
Accrued taxes	(52,905)	34,448	3,800
Accrued interest	(5,458)	1,717	(2,564)
Other	1,272	18,970	11,780
Net cash provided from operating activities	189,757	506,722	262,653
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing			
Long-term debt	382,400		300,000
Short-term borrowings, net	5,194		17,547
Redemptions and Repayments			
Long-term debt	(207,231)	(72,536)	(308,872)
Short-term borrowings, net		(67,187)	
Common stock	(77,000)		
Preferred stock	(13,312)		
Dividend Payments			
Common stock	(100,000)	(158,000)	(90,000)
Preferred stock	(354)	(500)	(500)
Net cash used for financing activities	(10,303)	(298,223)	(81,825)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(160,264)	(209,118)	(178,877)
Loan repayments from (loans to) associated companies, net	(6,037)	2,017	(857)
Proceeds from nuclear decommissioning trust fund sales	162,655	148,337	79,510
Investments in nuclear decommissioning trust funds	(165,550)	(151,232)	(82,405)
Other	(10,319)	1,437	1,692

Net cash used for investing activities	(179,515)	(208,559)	(180,937)
Net decrease in cash and cash equivalents	(61)	(60)	(109)
Cash and cash equivalents at beginning of year	102	162	271
Cash and cash equivalents at end of year	$ 41	$ 102	$ 162
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year			
Interest (net of amounts capitalized)	$ 80,101	$ 78,750	$ 83,341
Income taxes	$ 134,279	$ 12,385	$ 58,549

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF TAXES

For the Years Ended December 31,	2006	2005	2004
		(In thousands)	
GENERAL TAXES:			
New Jersey Transitional Energy Facilities Assessment*	$ 50,255	$ 52,026	$ 49,455
Social security and unemployment	8,716	7,682	8,287
Real and personal property	4,762	4,567	4,894
Other	192	263	156
Total general taxes	$ 63,925	$ 64,538	$ 62,792
PROVISION FOR INCOME TAXES:			
Currently payable			
Federal	$ 78,447	$ 77,783	$ 27,701
State	24,388	21,899	14,617
	102,835	99,682	42,318
Deferred, net			
Federal	33,870	27,335	50,817
State	10,918	10,167	5,657
	44,788	37,502	56,474
Investment tax credit amortization	(892)	(1,338)	(1,587)
Total provision for income taxes	$ 146,731	$ 135,846	$ 97,205
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 337,338	$ 318,773	$ 204,831
Federal income tax expense at statutory rate	$ 118,068	$ 111,571	$ 71,691
Increases (reductions) in taxes resulting from			
Amortization of investment tax credits	(892)	(1,338)	(1,587)
State income taxes, net of federal income tax benefit	22,948	20,843	13,178
Other, net	6,607	4,770	13,923
Total provision for income taxes	$ 146,731	$ 135,846	$ 97,205
ACCUMULATED DEFERRED INCOME TAXES AS OF 2 DECEMBER 31:			
Property basis differences	$ 436,122	$ 416,005	$ 361,640
Deferred sale and leaseback costs	(19,825)	(18,942)	(17,836)
Purchase accounting basis difference	(1,253)	(1,253)	(1,253)
Sale of generation assets	236	(17,861)	(17,861)
Regulatory transition charge	253,626	227,379	213,665
Customer receivables for future income taxes	3,655	6,589	(27,239)
Oyster Creek securitization	161,862	173,177	184,245
Other comprehensive income	(43,645)	(1,402)	(38,353)
Nuclear decommissioning	(16,204)	(9,881)	(11,178)

Employee benefits	35,818	29,182	1,652
Other	(6,448)	9,041	(1,741)
Net deferred income tax liability	$ 803,944	$ 812,034	$ 645,741

* Collected from customers through regulated rates and included in revenue in the Consolidated Statements of Income. The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION:

The consolidated financial statements include JCP&L (Company) and its wholly-owned subsidiaries. The Company is a wholly-owned subsidiary of FirstEnergy. FirstEnergy also holds directly all of the issued and outstanding common shares of its other principal electric utility operating subsidiaries, including OE, CEI, TE, ATSI, Met Ed and Penelec.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, NJBPU and the FERC. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

The Company consolidates all majority-owned subsidiaries, over which the Company exercises control and, when applicable, entities for which the Company has a controlling financial interest and VIEs for which the Company or any of its subsidiaries is the primary beneficiary. Intercompany transactions and balances are eliminated in consolidation. Investments in non-consolidated affiliates (20-50% owned companies, joint ventures and partnerships) over which the Company has the ability to exercise significant influence, but not control, are accounted for on the equity basis.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications did not change previously reported earnings for 2005 and 2004.

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-

The Company accounts for the effects of regulation through the application of SFAS 71 since its 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 if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

Regulatory Assets-

The Company recognizes, as regulatory assets, costs which the FERC and the NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Company s regulatory plan. The Company continues to bill and collect cost-based rates for its transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Company continue the application of SFAS 71 to those

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operations. As of December 31, 2006, regulatory assets that do not earn a return totaled approximately $128 million, consisting of outage funding costs ($32 million), post-employment benefit costs ($20 million) and reliability costs ($14 million).

	2006	2005
	(In millions)	
Non-utility generation	$ 1,399	$ 1,713
Regulatory transition costs	739	464
Basic generation service	69	52
Societal benefits charge	11	29
Property losses and unrecovered plant costs	19	29
Customer receivables for future income taxes	22	31
Employee post-retirement benefit costs	20	23
Loss on reacquired debt	11	10
Reliability costs	14	23
Component removal costs	(148)	(148)
Other	(4)	1
Total	$ 2,152	$ 2,227

Regulatory transition charges as of December 31, 2006 for the Company are approximately $2.2 billion. Deferral of above-market costs from power supplied by NUGs to the Company are approximately $1.4 billion and are being recovered through BGS and MTC revenues. The liability for projected above-market NUG costs and corresponding regulatory asset are adjusted to fair value at the end of each quarter. Recovery of the remaining regulatory transition costs is expected to continue under the provisions of the various regulatory proceedings in New Jersey.

(B) CASH AND SHORT TERM FINANCIAL INSTRUMENTS-

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.

(C) REVENUES AND RECEIVABLES-

The Company s principal business is providing electric service to customers in New Jersey. The Company s 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 between the last meter reading and the end of the month. This estimate includes many factors including 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 Company accrues the estimated unbilled amount receivable as revenue and reverses the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2006, with respect to any particular segment of the Company s customers. Total customer receivables were $254 million (billed $128 million and unbilled $126 million) and $258 million (billed $157 million and unbilled $101 million) as of December 31, 2006 and 2005, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

The majority of the Company s property, plant and equipment is reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. In addition to its wholly-owned facilities, the Company holds a 50% ownership interest in Yards Creek Pumped Storage Facility, and its net book value was approximately $20 million as of December 31, 2006. The costs of normal maintenance, repairs and minor

replacements are expensed as incurred. The Company s accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 2.1% in 2006, 2.2% in 2005 and 2.1% in 2004.

ASSET IMPAIRMENTS-

Long Lived Assets-

The Company evaluates the carrying value of its long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, 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 estimated by using available market valuations or the long-lived asset s expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

Investment-

At the end of each reporting period, the Company evaluates its investments for impairment. In accordance with SFAS 115 and FSP SFAS 115-1 and SFAS 124-1, 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. The Company 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 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. The recovery of amounts contributed to the Company s decommissioning trusts is subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from or refunded to customers. The fair value and unrealized gains and losses of the Company s investments are disclosed in Note 4(B) and (C).

Goodwill-

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, the Company evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated, the Company recognizes a loss calculated as the difference between the implied fair value of a reporting unit s goodwill and the carrying value of the goodwill. The Company s 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. The forecasts used in the Company s evaluation of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on the Company s future evaluations of goodwill. As of December 31, 2006, the Company had recorded goodwill of approximately $2.0 billion related to the merger. In 2006 and 2005, the Company adjusted goodwill to reverse pre-merger tax accruals related to the GPU acquisition.

(F) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder s equity excluding the effect from the adoption of SFAS 158 at

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December 31, 2006, except those resulting from transactions with FirstEnergy and preferred stockholders. As of December 31, 2006, AOCL consisted of a net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of tax benefits (see Note 3) of $42 million and unrealized losses or derivative instrument hedges of $2 million. As of December 31, 2005, AOCL consisted of unrealized losses on derivative instrument hedges of $2 million.

(G) INCOME TAXES-
Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company 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 used 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 carry forward 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. The Company is included in FirstEnergy s consolidated federal income tax return. The consolidated tax liability is allocated on a stand-alone company basis, with the Company recognizing the tax benefit for any tax losses or credits it contributes to the consolidated return.

(H) TRANSACTIONS WITH AFFILIATED COMPANIES-
Operating expenses and other income included transactions with affiliated companies, primarily FESC, NGC and FES. FESC provides legal, accounting, financial and other corporate support services to the Company. Through the BGS auction process, FES was a supplier of power to the Company through May 31, 2006. The primary affiliated companies transactions are as follows:

	2006	2005	2004
		(In millions)	
Revenues:			
Wholesale sales affiliated companies	$ 14	$ 33	$ 49
Expenses:			
Service Company support services	93	94	95
Power purchased from FES	25	78	71

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

3. PENSION AND OTHER POST-RETIREMENT BENEFITS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed 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. FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan on January 2, 2007 (Company s share was $18 million). Projections indicated that additional cash contributions will not be required before 2016.

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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. The Company recognizes the expected cost of providing other post-retirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy 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. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. 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 and 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 December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires an employer to recognize an asset or liability for the overfunded or underfunded status of their pension and other post-retirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan s assets and the projected benefit obligation. For any other post-retirement benefit plan, the asset or liability is the difference between the fair value of the plan s assets and the accumulated post-retirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in AOCL, net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. JCP&L s incremental impact of adopting SFAS 158 was a decrease of $153 million in pension assets, a decrease of $69 million in pension liabilities and a decrease in AOCL of $42 million, net of tax.

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With the exception of the Company s share of net pension (asset) liability at the end of year and net periodic pension expense, the following tables detail the Consolidated FirstEnergy pension plan and OPEB.

Obligations and Funded Status	**Pension Benefits**		**Other Benefits**	
As of December 31	**2006**	**2005**	**2006**	**2005**
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,750	$ 4,364	$ 1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants contributions			20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy			6	
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$ 4,861	$ 4,750	$ 1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,524	$ 3,969	$ 573	$ 564
Actual return on plan assets	567	325	69	33
Company contribution		500	54	58
Plan participants contribution			20	18
Benefits paid	(273)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$ 4,818	$ 4,524	$ 607	$ 573
Funded status	$ (43)	$ (226)	$ (594)	$ (1,311)
Accumulated benefit obligation	$ 4,447	$ 4,327		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$	$ 1,023	$	$
Current liabilities				
Noncurrent liabilities	(43)		(594)	(1,057)
Net pension asset (liability) at end of year	$ (43)	$ 1,023)	$ (594)	$ (1,057)
Company s share of net pension asset (liability) at end of year	$ 15	$ 148	$ (8)	$ (70)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$	$ (1,190)	$
Actuarial (gain) loss	982		702	
Net amount recognized	$ 1,045	$	$ (488)	$
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27

Real estate	5	2	1	
Private equities	1			
Cash	1	2	1	2
Total	100%	100%	100%	100%

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Estimated Items to Be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
Prior service cost (credit)	$ 10	$ (149)
Actuarial (gain) loss	$ 41	$ 45

Components of Net Periodic Benefit Costs	Pension Benefits 2006	2005	2004	Other Benefits 2006	2005	2004
			(In millions)			
Service cost	$ 83	$ 77	$ 77	$ 34	$ 40	$ 36
Interest cost	266	254	252	105	111	112
Expected return on plan assets	(396)	(345)	(286)	(46)	(45)	(44)
Amortization of prior service cost	10	8	9	(76)	(45)	(40)
Amortization of transition obligation						
Recognized net actuarial loss	58	36	39	56	40	39
Net periodic cost	$ 21	$ 30	$ 91	$ 73	$ 101	$ 103
Company s share of net periodic cost	$ (5)	$ (1)	$ 7	$ 2	$ 7	$ 5

Weighted Average Assumptions Used to Determine Net Periodic Benefit Costs for the Years Ended December 31	Pension Benefits 2006	2005	2004	Other Benefits 2006	2005	2004
Discount rate	5.75%	6.00%	6.25%	5.75%	6.00%	6.25%
Expected long term return on assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%	3.50%			

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 post-retirement 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 the Company s pension trusts. The long-term rate of return is developed considering the portfolio s asset allocation strategy.

FirstEnergy 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. Furthermore, 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 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.

Assumed Health Care Cost Trend Rates

As of December 31	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
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)	2011-2013	2010-2012

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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	$ 6	$ (5)
Effect on accumulated post-retirement benefit obligation	$ 33	$ (29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012-2016	1,606	537

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

(A) LONG-TERM DEBT-

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

	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Long-term debt	$ 1,366	$ 1,388	$ 1,191	$ 1,214

The fair value of long-term debt reflects 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 year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the Company s ratings.

(B) INVESTMENTS-

Investments other than cash and cash equivalents are available-for-sale securities primarily held in the spent nuclear fuel trust. The Company periodically evaluates its investments for other-than-temporary impairment. They first consider their intent and ability to hold the 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 investments for impairment. The following table provides the approximate fair value and related carrying amounts of investments except investments of $2 million excluded by SFAS 107, Disclosures about Fair Values of Financial Instruments , as of December 31:

	2006		2005	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
	(In millions)			
Debt securities:				
Government obligations(1)	169	165	166	162

(1) Excludes $2 million of cash in 2006.

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The spent nuclear fuel disposal investments consist of debt securities classified as available-for-sale with the fair value determined based on quoted market prices. The average maturity of the securities as of December 31 is 7 years for 2006 and 6 years for 2005.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values for the above investments:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 169		4	165	166		4	162

Proceeds from the sale of investments, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2006 were as follows:

	2006	2005	2004
		(In millions)	
Proceeds from sales	$ 61	$ 59	$ 204
Realized gains			4
Realized losses	2		
Interest and dividend income	8	9	8

(C) NUCLEAR DECOMMISSIONING TRUST FUND INVESTMENTS-
Nuclear decommissioning trust investments are classified as available-for-sale. The Company has no securities held for trading purposes. The following table provides the approximate carrying value, which equals fair value of the nuclear decommissioning trusts as of December 31, 2006 and 2005, respectively. The fair value was determined using the specific identification method of investments other than cash and cash equivalents as of December 31.

	2006	2005
	(In millions)	
Debt securities		
Government obligations	$ 53	$ 51
Corporate debt securities	14	11
	$ 67	$ 62
Equity securities	97	84
	$ 164	$ 146

The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for decommissioning trust investments as of December 31:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 65	$ 2	$	$ 67	$ 60	$ 2	$	$ 62

Equity securities	73		24			97	73		12		1	84
	$ 138	$	26	$		$ 164	$ 133	$	14	$	1	$ 146

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Proceeds from the sale of decommissioning trust investments, gross realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2006 were as follows:

	2006	2005	2004
		(In millions)	
Proceeds from sales	$ 164	$ 121	$ 119
Gross realized gains	1	4	15
Gross realized losses	3	5	1
Interest and dividend income	5	4	4

The Company s decommissioning trusts are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are 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.

5. LEASES:

Consistent with the regulatory treatment, the rentals for operating leases are charged to operating expenses on the Consolidated Statements of Income. The Company s most significant operating leases relate to the sale and leaseback of a portion of its ownership interest in the Merrill Creek Reservoir project and the lease of vehicles.

Such costs for the three years ended December 31, 2006 are summarized as follows:

	2006	2005	2004
		(In millions)	
Operating leases:			
Interest element	$ 2.8	$ 2.6	$ 2.6
Other	4.5	3.2	3.7
Total rentals	$ 7.3	$ 5.8	$ 6.3

The future minimum lease payments as of December 31, 2006 are:

	Operating Leases (In millions)
2007	$ 8.3
2008	8.5
2009	8.5
2010	8.0
2011	7.0
Years thereafter	62.1
Total minimum lease payments	$ 102.4

6. VARIABLE INTEREST ENTITIES:

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the residual economic risks and rewards. FirstEnergy adopted FIN 46R for special-purpose entities as of December 31, 2003 and for all other entities in the first quarter of 2004. The Company consolidates a VIE when it is determined to be the VIE s primary beneficiary as defined by FIN 46R.

The Company has evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Company and the contract price for power is correlated with the plant s variable costs of production. The Company maintains several long-term power purchase agreements with NUG entities. The agreements were structured pursuant to the Public Utility Regulatory Policies Act of 1978. The Company was not involved in the creation of, and has no equity or debt invested in, these entities.

The Company has determined that for all but five of these entities, the Company has no variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. The Company may hold variable interests in the remaining five entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants.

As required by FIN 46R, the Company periodically requests the information necessary from these entities to determine whether they are VIEs or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which in most cases, was deemed by the requested entity to be proprietary. As such, the Company applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. As of December 31, 2006, the net above-market loss liability recognized was $221 million. The purchased power costs from these entities during 2006, 2005, and 2004 were $81 million, $101 million, and $94 million, respectively.

7. REGULATORY MATTERS:

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. Canada Power System Outage Task Force) regarding enhancements to regional reliability. In 2004, FirstEnergy completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training and emergency response preparedness recommended for completion in 2004. On July 14, 2004, NERC independently verified that FirstEnergy had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions noted by FirstEnergy, which exceptions are now essentially complete. FirstEnergy is proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new equipment or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability entities may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in the Company s service area in 2002 and 2003, the NJBPU had implemented reviews into the Company s service reliability. In 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by the Company and a timetable for completion and endorsed the Company s ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a Stipulation that incorporates the final report of an SRM who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of the Company s Planning and Operations and Maintenance programs and practices (Focused Audit). On February 11, 2005, the Company met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. The Company filed a comprehensive response to the NJBPU on July 14, 2006. The Company continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC s review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume compliance monitoring and enforcement responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC s certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of pro forma delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. The regional entity may be delegated authority by the ERO, subject to FERC approval, for compliance and enforcement of reliability standards adopted by the ERO and approved by the FERC. The ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make compliance filings addressing governance and non-governance issues and the regional delegation agreements. On September 18, 2006 and October 18, 2006, NERC submitted compliance filings addressing the governance and non-governance issues identified in the FERC ERO Certification Order, dated July 20, 2006. On October 30, 2006, the FERC issued an order accepting most of NERC s governance filings. On January 18, 2007, the FERC issued an order largely accepting NERC s compliance filings addressing non-governance issues, subject to an additional compliance filing requirement.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards, as well as for approval with the relevant Canadian authorities. These reliability standards are based, with some modifications and additions, on the current NERC Version 0 reliability standards. The reliability standards filing was subsequently evaluated by the FERC on May 11, 2006, leading to the FERC staffs release of a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff s preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a NOPR on the proposed reliability standards on October 20, 2006. In the NOPR, the FERC proposed to approve 83 of the 107 reliability standards and directed NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not approved remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification within the NOPR regarding the proposed application of final standards and guidance with regard to technical improvements of the standards. On November 15, 2006, NERC submitted several revised reliability standards and three new proposed reliability standards. Interested parties were provided the opportunity to comment on the NOPR (including the revised standards submitted by NERC in November) by January 3, 2007. Numerous parties, including FirstEnergy, filed comments on the NOPR on January 3, 2007. Mandatory reliability standards enforceable with penalties are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC s 2007 budget and business plan subject to certain compliance filings.

On November 29, 2006, NERC submitted an additional compliance filing with the FERC regarding the Compliance Monitoring and Enforcement Program (CMEP) along with the proposed Delegation Agreements between the ERO and the regional reliability entities. The FERC provided opportunity for interested parties to comment on the CMEP by January 10, 2007. We, as well as other parties, moved to intervene and submitted responsive comments on January 10, 2007. This filing is pending before the FERC.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils completed the consolidation of these regions into a single new regional reliability organization known as Reliability*First* Corporation. Reliability*First* began operations as a regional reliability council under NERC on January 1, 2006 and on November 29, 2006 filed a proposed Delegation Agreement with NERC to obtain certification consistent with the final rule as a regional entity under the ERO. All of FirstEnergy s facilities are located within the Reliability*First* region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC filed these proposed standards with the FERC and relevant Canadian authorities for approval. The cyber security standards were not included in the October 20, 2006 NOPR and are being addressed in a separate FERC docket. On December 11, 2006, the FERC Staff provided its preliminary assessment of these proposed mandatory reliability standards and again cited various deficiencies in the proposed standards, providing interested parties with the opportunity to comment on the assessment by February 12, 2007.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt more strict reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for its bulk power system in the future, it could have a material adverse effect on FirstEnergy s and its subsidiaries financial condition, results of operations and cash flows.

The Company is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2006, the accumulated deferred cost balance totaled approximately $369 million. New Jersey law allows for securitization of the Company s deferred balance upon application by the Company and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, the Company filed for approval to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved the Company s request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly-owned subsidiary of the Company, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, the Company filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, the Company filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On July 18, 2006, the Company further requested an additional $14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual $110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that the Company absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, the Company also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds $350 million at any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. The Company filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

In accordance with an April 28, 2004 NJBPU order, the Company filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by

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New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, the Company filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, the Company filed a response to the Ratepayer Advocate s comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or the Company. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders.

New Jersey statutes require that the state periodically undertake a planning process, known as the Energy Master Plan (EMP), to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor s Office and the Governor s Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006 the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of the State s electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Unit prices for electricity should remain no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to attain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in late 2007. A final draft of the EMP is expected to be presented to the Governor in the fall of 2007 with further public hearings anticipated in early 2008. At this time the Company cannot predict the outcome of this process nor determine its impact.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, the Company, Met-Ed, Penelec, and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in early 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. The Company, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. American Electric Power Company, Inc. filed in opposition proposing to create a postage stamp rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the FERC Trial Staffs position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. The Company, Met Ed and Penelec, as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in early 2007.

On January 17, 2007, the Company filed a petition with the NJBPU seeking approval of the sale of the Forked River Generating Station to FRP, which is indirectly owned by Maxim Power (USA), Inc., based upon terms and conditions set forth in the Purchase and Sale Agreement and other related agreements, including a Tolling Agreement with FES and a PJM Interconnection Agreement. FRP will assume all on-site environmental liabilities arising on and after the closing of the sale and the Company will retain pre-closing environmental liabilities. In addition to approval by the NJBPU, the sale is subject to the receipt of regulatory approvals from the FERC and the New Jersey Department of Environmental Protection.

On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule will not be effective until 60 days after publication in the Federal Register. The final rule has not yet been fully evaluated to assess its impact on our operations.

8. CAPITALIZATION:

(A) RETAINED EARNINGS-

In general, the Company s first mortgage indenture restricts the payment of dividends or distributions on or with respect to the Company s common stock to amounts credited to earned surplus since the date of its indenture. As of December 31, 2006, the Company had retained earnings available to pay common stock dividends of $144 million, net of amounts restricted under the Company s first mortgage indenture.

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(B) LONG-TERM DEBT-
Securitized Transition Bonds-

The consolidated financial statements of JCP&L include the results 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 $320 million of 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 $182 million of 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 Consolidated Balance Sheet. As of December 31, 2006, $429 million of transition bonds are 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 consists 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-

The Company's first mortgage indenture, which secures all of the Company s FMB, serves as a direct first mortgage lien on substantially all of the Company s property and franchises, other than specifically excepted property.

The Company has various debt covenants under its financing arrangements. The most restrictive of these relate to the nonpayment of interest and/or principal on debt, which could trigger a default. Cross-default provisions also exist between FirstEnergy and the Company.

Based on the amount of bonds authenticated by the Trustee through December 31, 2006, the Company s annual sinking fund requirements for all bonds issued under the mortgage amount to $10 million. The Company could fulfill its sinking fund obligation by providing refundable bonds, property additions or cash to the Trustee. Sinking fund requirements for FMB and maturing long-term debt for the next five years are:

	(In millions)
2007	$33
2008	27
2009	29
2010	31
2011	32

9. ASSET RETIREMENT OBLIGATION:

JCP&L has recognized legal obligations under SFAS 143 for nuclear plant decommissioning. In addition, the Company has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47, which was implemented on December 31, 2005. SFAS 143 requires recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Over time, the capitalized costs are depreciated and the present value of the ARO increases, resulting in a period expense. However, rate-regulated entities may recognize a regulatory asset or liability instead of an expense if the criteria for such treatment are met. Upon retirement, a gain or loss would be recognized if the cost to settle the retirement obligation differs from the carrying amount.

The ARO liability of $84 million as of December 31, 2006 primarily relates to the nuclear decommissioning of TMI-2. The obligation to decommission this unit was developed based on site specific studies performed by an independent engineer. The Company uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

The Company maintains the nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2006, the fair value of the decommissioning trust assets was $164 million.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143. The effect on income as if FIN 47 had been applied during 2004 was immaterial.

The following table describes the changes to the ARO balances during 2006 and 2005.

ARO Reconciliation	**2006**	**2005**
	(In millions)	
Balance at beginning of year	$ 80	$ 73
Accretion	4	5
FIN 47 ARC upon adoption		2
Balance at end of year	$ 84	$ 80

10. SHORT-TERM BORROWINGS:

Short-term borrowings outstanding as of December 31, 2006 consisted of $187 million of borrowings from affiliates. On August 24, 2006, the Company, FirstEnergy, OE, Penn, CEI, TE, Penelec, Met-Ed, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility, which replaced the prior $2 billion credit facility. Subject to specified conditions, FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two 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 sublimit, as well as applicable regulatory and other limitations. The Company s borrowing limit under the facility is $425 million. The average interest rate on short-term borrowings outstanding as of December 31, 2006 and 2005 was 5.6% and 4.0%, respectively.

11. COMMITMENTS, GUARANTEES AND CONTINGENCIES:

(A) NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to $10.8 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. Based on its present ownership interest in TMI-2, the Company is exempt from any potential assessment under the industry retrospective rating plan.

The Company is also insured as to its interest in TMI-2 under a policy issued to the operating company for the plant. Under this policy, $150 million is provided for property damage and decontamination and decommissioning costs. Under this policy, the Company can be assessed a maximum of approximately $0.2 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Company intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at TMI-2 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 the Company s insurance policies, or to the extent such insurance becomes unavailable in the future, the Company would remain at risk for such costs.

(B) ENVIRONMENTAL MATTERS-

The Company accrues environmental 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. Unasserted claims are reflected in the Company s determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

The Company has been named as a PRP 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 PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2006, based on estimates of the total costs of cleanup, the Company s proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. In addition, the Company has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey. Those costs are being recovered by the Company through a non-bypassable SBC. Total liabilities of approximately $59 million have been accrued through December 31, 2006.

(C) 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 the Company s territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey s electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, the Company provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against the Company, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to the Company and dismissed the plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted the Company s motion to decertify the class and denied plaintiffs motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision on July 8, 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of

JCP&L transformers in Red Bank, New Jersey. In 2005, the Company renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Because it effectively terminates this class action, plaintiffs appealed this ruling to the New Jersey Appellate Division, where the matter is currently pending. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2006.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy s service area. The U.S. Canada Power System Outage Task Force s final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy s Web site (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility s system. The final report contained 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy s implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy is also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy s subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy s motion to dismiss. The plaintiff has not appealed.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. Although unable to predict the impact of these proceedings, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

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Other Legal Matters-

The Company s bargaining unit employees filed a grievance challenging the Company s 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, a Company appeal of the award filed on October 18, 2005. The Company intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. The Company recognized a liability for the potential $16 million award in 2005.

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.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

SFAS 159 The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. The Standard requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company s choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157, Fair Value Measurements, and SFAS 107, Disclosures about Fair Value of Financial Instruments. The Company is currently evaluating the impact of this Statement on its financial statements.

SFAS 157 Fair Value Measurements

In September 2006, the FASB issued SFAS 157, which establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The Company is currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). We adopted FIN 46(R) in the first quarter of 2004, consolidating VIEs when we are determined to be the VIE s primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if

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any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1: Analyze the nature of the risks in the entity

Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. The Company does not expect this Statement to have a material impact on its financial statements.

FIN 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company does not expect this Statement to have a material impact on its financial statements.

13. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

Three Months Ended	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
			(In millions)	
Revenues	$ 575.8	$ 611.5	$ 911.1	$ 569.3
Expenses	502.3	515.8	755.1	490.9
Operating Income	73.5	95.7	156.0	78.4
Other Expense	(16.2)	(16.8)	(18.3)	(15.0)
Income Before Income Taxes	57.3	78.9	137.7	63.4
Income Taxes	23.6	38.6	58.3	26.2
Net Income	$ 33.7	$ 40.3	$ 79.4	$ 37.2
Earnings on Common Stock	$ 33.6	$ 40.2	$ 78.5	$ 37.3

Three Months Ended	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
			(In millions)	
Revenues	$ 529.1	$ 595.3	$ 900.3	$ 577.6
Expenses	482.2	478.8	753.5	499.4
Operating Income	46.9	116.5	146.8	78.2
Other Expense	(20.2)	(19.5)	(14.7)	(15.2)

Income Before Income Taxes	26.7	97.0	132.1	63.0
Income Taxes	13.2	42.7	58.1	21.8
Net Income	$ 13.5	$ 54.3	$ 74.0	$ 41.2
Earnings on Common Stock	$ 13.3	$ 54.2	$ 73.7	$ 41.2

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Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of

Directors of Jersey Central Power & Light Company:

We have reviewed the accompanying consolidated balance sheet of Jersey Central Power & Light Company and its subsidiaries as of September 30, 2007 and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2007 and 2006 and the consolidated statement of cash flows for the nine-month periods ended September 30, 2007 and 2006. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2006, and the related consolidated statements of income, capitalization, common stockholder s equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company s change in its method of accounting for defined benefit pension and other postretirement benefit plans as of December 31, 2006, as discussed in Note 3 to those consolidated financial statements) dated February 27, 2007, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2006, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Cleveland, Ohio

October 31, 2007

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
		(in thousands)		
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 1,018,049	$ 895,389	$ 2,457,146	$ 2,059,499
Excise tax collections	15,168	15,679	39,849	38,845
Total revenues	1,033,217	911,068	2,496,995	2,098,344
EXPENSES:				
Purchased power	654,418	546,125	1,505,420	1,204,880
Other operating costs	87,010	90,578	236,225	245,711
Provision for depreciation	22,032	21,099	63,867	62,553
Amortization of regulatory assets	107,837	78,052	296,955	210,323
General taxes	18,631	19,187	51,183	49,691
Total expenses	889,928	755,041	2,153,650	1,773,158
OPERATING INCOME	143,289	156,027	343,345	325,186
OTHER INCOME (EXPENSES):				
Miscellaneous income	2,967	2,091	9,266	8,162
Interest expense	(24,666)	(21,437)	(71,576)	(62,420)
Capitalized interest	483	1,004	1,559	2,933
Total other expense	(21,216)	(18,342)	(60,751)	(51,325)
INCOME BEFORE INCOME TAXES	122,073	137,685	282,594	273,861
INCOME TAXES	46,275	58,316	118,637	120,506
NET INCOME	75,798	79,369	163,957	153,355
PREFERRED STOCK DIVIDEND REQUIREMENTS		917		1,167
EARNINGS ON COMMON STOCK	$ 75,798	$ 78,452	$ 163,957	$ 152,188
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 75,798	$ 79,369	$ 163,957	$ 153,355
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and other postretirement benefits	(2,114)		(6,344)	
Unrealized gain on derivative hedges	69	100	235	207
Other comprehensive income (loss)	(2,045)	100	(6,109)	207
Income tax expense (benefit) related to other comprehensive income	(994)	41	(2,973)	84

Other comprehensive income (loss), net of tax	(1,051)	59	(3,136)	123
TOTAL COMPREHENSIVE INCOME	$ 74,747	$ 79,428	$ 160,821	$ 153,478

The accompanying Notes to Consolidated Financial Statements as they relate to Jersey Central Power & Light Company are an integral part of these statements.

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2007	December 31, 2006
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 77	$ 41
Receivables		
Customers (less accumulated provisions of $4,821,000 and $3,524,000, respectively, for uncollectible accounts)	396,700	254,046
Associated companies	369	11,574
Other (less accumulated provisions of $718,000 and $204,000, respectively, for uncollectible accounts)	62,235	40,023
Notes receivable associated companies	22,734	24,456
Materials and supplies, at average cost	1,915	2,043
Prepaid taxes	41,670	13,333
Other	14,080	18,076
	539,780	363,592
UTILITY PLANT:		
In service	4,122,325	4,029,070
Less Accumulated provision for depreciation	1,490,846	1,473,159
	2,631,479	2,555,911
Construction work in progress	84,199	78,728
	2,715,678	2,634,639
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	172,278	171,045
Nuclear plant decommissioning trusts	177,217	164,108
Other	2,075	2,047
	351,570	337,200
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	1,757,516	2,152,332
Goodwill	1,826,190	1,962,361
Pension assets	43,183	14,660
Other	15,124	17,781
	3,642,013	4,147,134
	$ 7,249,041	$ 7,482,565
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Current payable long-term debt	$ 26,680	$ 32,683
Short-term borrowings Associated companies	155,395	186,540
Accounts payable Associated companies	22,399	80,426
Other	211,788	160,359
Accrued taxes	25,793	1,451
Accrued interest	27,520	14,458

Cash collateral from suppliers	68	32,311
Other	85,746	96,139
	555,389	604,367
CAPITALIZATION:		
Common stockholder s equity		
Common stock, $10 par value, authorized 16,000,000 shares 14,421,637 and 15,009,335 shares outstanding, respectively	144,216	150,093
Other paid-in capital	2,657,775	2,908,279
Accumulated other comprehensive loss	(47,390)	(44,254)
Retained earnings	266,342	145,480
Total common stockholder s equity	3,020,943	3,159,598
Long-term debt and other long-term obligations	1,568,296	1,320,341
	4,589,239	4,479,939
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	872,305	1,182,108
Accumulated deferred income taxes	762,782	803,944
Nuclear fuel disposal costs	190,524	183,533
Asset retirement obligations	88,334	84,446
Other	190,468	144,228
	2,104,413	2,398,259
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 7,249,041	$ 7,482,565

The accompanying Notes to Consolidated Financial Statements as they relate to Jersey Central Power & Light Company are an integral part of these balance sheets.

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2007	**2006**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 163,957	$ 153,355
Adjustments to reconcile net income to net cash from operating activities		
Provision for depreciation	63,867	62,553
Amortization of regulatory assets	296,955	210,323
Deferred purchased power and other costs	(157,201)	(213,621)
Deferred income taxes and investment tax credits, net	(23,786)	25,217
Accrued compensation and retirement benefits	(17,543)	(4,196)
Cash collateral returned to suppliers	(32,243)	(108,926)
Pension trust contribution	(17,800)	
Decrease (increase) in operating assets		
Receivables	(153,660)	(50,337)
Materials and supplies	127	86
Prepaid taxes	(28,337)	(29,923)
Other current assets	2,079	(2,118)
Increase (decrease) in operating liabilities		
Accounts payable	(6,598)	(8,131)
Accrued taxes	29,318	(16,992)
Accrued interest	13,062	16,296
Tax collections payable	(12,478)	(10,316)
Other	(7,440)	(4,814)
Net cash provided from operating activities	112,279	18,456
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing		
Long-term debt	549,999	382,400
Equity contribution from parent	4,636	
Redemptions and Repayments		
Long-term debt	(324,256)	(162,157)
Short-term borrowings, net	(31,145)	(44,162)
Common stock	(125,000)	
Preferred stock		(13,461)
Dividend Payments		
Common stock	(43,000)	(45,000)
Preferred stock		(354)
Net cash provided from financing activities	31,234	117,266
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(144,668)	(123,540)
Loan repayments from (loans to) associated companies, net	1,722	(8,638)
Sales of investment securities held in trusts	169,649	169,676

Purchases of investment securities held in trusts	(171,820)	(171,847)
Other	1,640	(1,417)
Net cash used for investing activities	(143,477)	(135,766)
Net increase (decrease) in cash and cash equivalents	36	(44)
Cash and cash equivalents at beginning of period	41	102
Cash and cash equivalents at end of period	$ 77	$ 58

The accompanying Notes to Consolidated Financial Statements as they relate to Jersey Central Power & Light Company are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy s principal business is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries: OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed and Penelec. Penn is a wholly owned subsidiary of OE. FirstEnergy s consolidated financial statements also include its other subsidiaries: 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.

These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2006 for FirstEnergy and the Companies. The consolidated unaudited financial statements of FirstEnergy, FES and each of the Companies reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. Certain businesses divested in 2006 have been classified as discontinued operations on the Consolidated Statements of Income (see Note 4). As discussed in Note 14, interim period segment reporting in 2006 was reclassified to conform with the current year business segment organizations and operations. 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.

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. 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) follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity s earnings is reported in the Consolidated Statements of Income.

The consolidated financial statements as of September 30, 2007 and for the three-month and nine-month periods ended September 30, 2007 and 2006 have been reviewed by PricewaterhouseCoopers LLP, an independent registered public accounting firm. Their report (dated October 31, 2007) is included on page F-31. The report of PricewaterhouseCoopers LLP states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Securities Exchange Act of 1934.

2. EARNINGS PER SHARE

Basic earnings per share of common stock is 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

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shares that could result if dilutive securities and other agreements to issue common stock were exercised. The pool of stock-based compensation tax benefits is calculated in accordance with SFAS 123(R). On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. A final purchase price adjustment of $27 million was settled in cash on April 2, 2007. On March 2, 2007, FirstEnergy repurchased approximately 14.4 million shares, or 4.5%, of its outstanding common stock through an additional accelerated share repurchase program at an initial price of $62.63 per share, or a total initial purchase price of approximately $900 million. The final purchase price for this program will be adjusted to reflect the volume-weighted average price of FirstEnergy s common stock during the period of time that the bank will acquire shares to cover its short position, which is expected to be by the end of 2007. The basic and diluted earnings per share calculations shown below reflect the impact associated with these accelerated share repurchase programs. FirstEnergy intends to settle, in cash or shares, any obligation on its part to pay the difference between the average of the daily volume-weighted average price of the shares as calculated under the March 2007 program and the initial price of the shares.

Reconciliation of Basic and Diluted Earnings per Share	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
	(In millions, except per share amounts)			
Income from continuing operations	$ 413	$ 452	$ 1,041	$ 983
Discontinued operations		2		(4)
Redemption premium on subsidiary preferred stock				(3)
Net earnings available for common shareholders	$ 413	$ 454	$ 1,041	$ 976
Average shares of common stock outstanding Basic	304	322	307	326
Assumed exercise of dilutive stock options and awards	3	3	4	3
Average shares of common stock outstanding Dilutive	307	325	311	329
Earnings per share:				
Basic earnings per share:				
Earnings from continuing operations	$ 1.36	$ 1.40	$ 3.39	$ 3.00
Discontinued operations		0.01		(0.01)
Net earnings per basic share	$ 1.36	$ 1.41	$ 3.39	$ 2.99
Diluted earnings per share:				
Earnings from continuing operations	$ 1.34	$ 1.39	$ 3.35	$ 2.98
Discontinued operations		0.01		(0.01)
Net earnings per diluted share	$ 1.34	$ 1.40	$ 3.35	$ 2.97

3. GOODWILL

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and more frequently as indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, FirstEnergy recognizes a loss calculated as the difference between the implied fair value of a reporting unit s goodwill and the carrying value of the goodwill. FirstEnergy s 2007 annual review was completed in the third quarter of 2007 with no impairment indicated.

FirstEnergy s goodwill primarily relates to its energy delivery services segment. In the third quarter of 2007, FirstEnergy adjusted goodwill for the former GPU companies due to the realization of tax benefits that had been

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reserved in purchase accounting. See Note 12 for a discussion of the tax implications related to the Bruce Mansfield Unit 1 sale and leaseback transaction. The following tables reconcile changes to goodwill for the three months and nine months ended September 30, 2007.

Three Months Ended	FirstEnergy	FES	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Balance as of July 1, 2007	$ 5,898	$ 24	$ 1,689	$ 501	$ 1,962	$ 496	$ 861
Adjustments related to GPU acquisition	(289)				(136)	(70)	(83)
Balance as of September 30, 2007	$ 5,609	$ 24	$ 1,689	$ 501	$ 1,826	$ 426	$ 778

Nine Months Ended	FirstEnergy	FES	CEI	TE	JCP&L	Met-Ed	Penelec
				(In millions)			
Balance as of January 1, 2007	$ 5,898	$ 24	$ 1,689	$ 501	$ 1,962	$ 496	$ 861
Adjustments related to GPU acquisition	(289)				(136)	(70)	(83)
Balance as of September 30, 2007	$ 5,609	$ 24	$ 1,689	$ 501	$ 1,826	$ 426	$ 778

4. DIVESTITURES AND DISCONTINUED OPERATIONS

In 2006, FirstEnergy sold its remaining FSG subsidiaries (Roth Bros., Hattenbach, Dunbar, Edwards and RPC) for an aggregate net after-tax gain of $2.2 million. Hattenbach, Dunbar, Edwards, and RPC are included in discontinued operations for the third quarter and nine months ended September 30, 2006; Roth Bros. did not meet the criteria for that classification.

In March 2006, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million. In June 2006, as part of the March agreement, FirstEnergy sold an additional 1.67% interest. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining 38.33% interest under the equity method. In the fourth quarter of 2006, FirstEnergy sold its remaining MYR interest for an after-tax gain of $8.6 million.

The income for the period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, results prior to the initial sale in March 2006, including the gain on the sale, are reported as discontinued operations.

Revenues associated with discontinued operations were $36 million and $211 million in the third quarter and first nine months of 2006, respectively. The following table summarizes the net income (loss) included in Discontinued Operations on the Consolidated Statements of Income for the three months and nine months ended September 30, 2006:

	Three Months	Nine Months
	(In millions)	
FSG subsidiaries	$ 2	$ (6)
MYR		2
Total	$ 2	$ (4)

5. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including prices for electricity, natural gas, coal 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 principally for hedging purposes. FirstEnergy s Risk Policy Committee, comprised of members of senior management, provides general management oversight for risk management activities throughout FirstEnergy. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criterion. Derivatives that meet that criterion are accounted for using traditional accrual accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criterion are recorded as other expense, as AOCL, or as part of the value of the hedged item, depending on whether or not it is designated as part of a hedge transaction, the nature of the hedge transaction and hedge effectiveness.

FirstEnergy hedges anticipated transactions using cash flow hedges. Such transactions include hedges of anticipated electricity and natural gas purchases and anticipated interest payments associated with future debt issues. The effective portion of such hedges are initially recorded in equity as other comprehensive income or loss and are subsequently included in net income as the underlying hedged commodities are delivered or interest payments are made. Gains and losses from any ineffective portion of cash flow hedges are included directly in earnings.

The net deferred losses of $52 million included in AOCL as of September 30, 2007, for derivative hedging activity, as compared to $58 million as of December 31, 2006, resulted from a net $10 million increase related to current hedging activity and a $16 million decrease due to net hedge losses reclassified to earnings during the nine months ended September 30, 2007. Based on current estimates, approximately $14 million (after tax) of the net deferred losses on derivative instruments in AOCL as of September 30, 2007 is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

FirstEnergy has entered into swaps that have been designated as fair value hedges of fixed-rate, long-term debt issues to protect against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates received, and interest payment dates match those of the underlying debt obligations. During the first nine months of 2007, FirstEnergy unwound swaps with a total notional value of $150 million, for which it incurred $8 million in cash losses that will be recognized as interest expense over the remaining maturity of each hedged security. As of September 30, 2007, FirstEnergy had interest rate swaps with an aggregate notional value of $600 million and a fair value of $(14) million.

During 2006 and the first nine months of 2007, FirstEnergy entered into several forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated issuances of fixed-rate, long-term debt securities for one or more of its subsidiaries as outstanding debt matures during 2007 and 2008. These derivatives are 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. During the first nine months of 2007, FirstEnergy terminated swaps with a notional value of $1.6 billion for which it paid $20 million, all of which were deemed effective. FirstEnergy will recognize the $20 million loss over the life of the associated future debt. As of September 30, 2007, FirstEnergy had forward swaps with an aggregate notional amount of $400 million and a fair value of $5 million.

6. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations under SFAS 143 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) in accordance with FIN 47.

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The ARO liability of $1.2 billion as of September 30, 2007 is primarily related to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. FirstEnergy utilized an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of September 30, 2007, the fair value of the decommissioning trust assets was approximately $2.1 billion.

The following tables analyze changes to the ARO balances during the three months and nine months ended September 30, 2007 and 2006, respectively.

Three Months Ended	**FirstEnergy**	**FES**	**OE**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
ARO Reconciliation								
Balance, July 1, 2007	$ 1,228	$ 784	$ 91	$ 2	$ 27	$ 87	$ 156	$ 79
Liabilities incurred								
Liabilities settled								
Accretion	19	13	1		1	1	2	2
Revisions in estimated cashflows								
Balance, September 30, 2007	$ 1,247	$ 797	$ 92	$ 2	$ 28	$ 88	$ 158	$ 81
Balance, July 1, 2006	$ 1,160	$ 743	$ 85	$ 2	$ 26	$ 82	$ 146	$ 74
Liabilities incurred								
Liabilities settled								
Accretion	19	13	2			1	3	2
Revisions in estimated cashflows								
Balance, September 30, 2006	$ 1,179	$ 756	$ 87	$ 2	$ 26	$ 83	$ 149	$ 76

Nine Months Ended	**FirstEnergy**	**FES**	**OE**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
ARO Reconciliation								
Balance, January 1, 2007	$ 1,190	$ 760	$ 88	$ 2	$ 27	$ 84	$ 151	$ 77
Liabilities incurred								
Liabilities settled	(2)	(1)						
Accretion	59	38	4		1	4	7	4
Revisions in estimated cashflows								
Balance, September 30, 2007	$ 1,247	$ 797	$ 92	$ 2	$ 28	$ 88	$ 158	$ 81
Balance, January 1, 2006	$ 1,126	$ 716	$ 83	$ 8	$ 25	$ 80	$ 142	$ 72
Liabilities incurred								
Liabilities settled	(6)			(6)				
Accretion	55	36	4		1	3	7	4
Revisions in estimated cashflows	4	4						
Balance, September 30, 2006	$ 1,179	$ 756	$ 87	$ 2	$ 26	$ 83	$ 149	$ 76

7. PENSION AND OTHER POSTRETIREMENT BENEFITS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its and its subsidiaries employees. The trusteed 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. FirstEnergy uses a December 31 measurement date for its pension and other postretirement benefit plans. The fair value of the plan assets represents the actual market value as of December 31, 2006. On January 2, 2007, FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan. Projections indicate that additional cash contributions are not expected to be required before 2016. FirstEnergy also 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 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 pension benefits and other postretirement benefits from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the health care plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

The components of FirstEnergy s net periodic pension and other postretirement benefit costs (including amounts capitalized) for the three months and nine months ended September 30, 2007 and 2006 consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension Benefits	**2007**	**2006**	**2007**	**2006**
		(In millions)		
Service cost	$ 21	$ 21	$ 63	$ 63
Interest cost	71	66	213	199
Expected return on plan assets	(112)	(99)	(337)	(297)
Amortization of prior service cost	2	2	7	7
Recognized net actuarial loss	10	15	31	44
Net periodic cost (credit)	$ (8)	$ 5	$ (23)	$ 16

	Three Months Ended September 30,		Nine Months Ended September 30,	
Other Postretirement Benefits	**2007**	**2006**	**2007**	**2006**
		(In millions)		
Service cost	$ 5	$ 9	$ 16	$ 26
Interest cost	17	26	52	79
Expected return on plan assets	(12)	(12)	(38)	(35)
Amortization of prior service cost	(37)	(19)	(112)	(57)
Recognized net actuarial loss	11	14	34	42
Net periodic cost (credit)	$ (16)	$ 18	$ (48)	$ 55

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Pension and other postretirement benefit obligations are allocated to FirstEnergy s subsidiaries employing the plan participants. FirstEnergy s subsidiaries capitalize employee benefit costs related to construction projects. The net periodic pension and other postretirement benefit costs (including amounts capitalized) recognized by FES and each of the Companies for the three months and nine months ended September 30, 2007 and 2006 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension Benefit Cost (Credit)	**2007**	**2006**	**2007**	**2006**
	(In millions)			
FES	$ 5.2	$ 9.9	$ 15.7	$ 29.9
OE	(4.0)	(1.5)	(11.9)	(4.5)
CEI	0.3	1.0	0.9	2.9
TE		0.2	(0.1)	0.7
JCP&L	(2.1)	(1.4)	(6.4)	(4.1)
Met-Ed	(1.7)	(1.7)	(5.1)	(5.2)
Penelec	(2.6)	(1.3)	(7.7)	(4.0)
Other FirstEnergy subsidiaries	(2.7)		(8.1)	
	$ (7.6)	$ 5.2	$ (22.7)	$ 15.7

	Three Months Ended September 30,		Nine Months Ended September 30,	
Other Postretirement Benefit Cost (Credit)	**2007**	**2006**	**2007**	**2006**
	(In millions)			
FES	$ (2.4)	$ 3.4	$ (7.4)	$ 10.2
OE	(2.7)	4.2	(8.0)	12.6
CEI	1.0	2.8	2.9	8.3
TE	1.2	2.0	3.7	6.1
JCP&L	(4.0)	0.6	(11.9)	1.8
Met-Ed	(2.5)	0.7	(7.7)	2.2
Penelec	(3.2)	1.8	(9.5)	5.4
Other FirstEnergy subsidiaries	(3.3)	2.7	(9.8)	7.9
	$ (15.9)	$ 18.2	$ (47.7)	$ 54.5

8. VARIABLE INTEREST ENTITIES

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the entity s residual economic risks and rewards. FirstEnergy and its subsidiaries consolidate VIEs when they are determined to be the VIE s primary beneficiary as defined by FIN 46R.

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. Ownership of PNBV includes a 3% equity interest by an

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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.

OE, CEI and TE are exposed to losses under the applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. OE, CEI and TE each have a maximum exposure to loss under these provisions of approximately $827 million, $758 million and $758 million, respectively, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the applicable plant worthless. Under the applicable sale and leaseback agreements, OE, CEI and TE have net minimum discounted lease payments of $606 million, $73 million and $429 million, respectively, that would not be payable if the casualty value payments are made.

Effective October 16, 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO. FGCO assumed all of CEI s and TE s obligations arising under those leases. However, CEI and TE will remain primarily liable on the leases and related agreements as to the lessors and other parties to the agreements. The assignment terminates automatically upon the termination of the underlying leases.

Power Purchase Agreements

In accordance with FIN 46R, FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Companies and the contract price for power is correlated with the plant s variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains approximately 30 long-term power purchase agreements 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 has determined that for all but eight of these entities, neither JCP&L, Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining eight entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. As required by FIN 46R, FirstEnergy periodically requests from these eight entities the information necessary to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R.

Since FirstEnergy 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. As of September 30, 2007, the net above-market loss liability projected for these eight NUG agreements was $158 million. Purchased power costs from these entities during the three months and nine months ended September 30, 2007 and 2006 are shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
JCP&L	$ 30	$ 29	$ 71	$ 63
Met-Ed	13	12	40	45
Penelec	7	8	22	22
Total	$ 50	$ 49	$ 133	$ 130

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Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the results 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 $320 million of 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 $182 million of 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 September 30, 2007, $404 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 consists 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 quarterly servicing fees of $157,000 payable from TBC collections.

9. INCOME TAXES

On January 1, 2007, FirstEnergy adopted FIN 48, which provides guidance for accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. This interpretation 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. FIN 48 also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

As of January 1, 2007, the total amount of FirstEnergy s unrecognized tax benefits was $268 million. FirstEnergy recorded a $2.7 million cumulative effect adjustment to the January 1, 2007 balance of retained earnings to increase reserves for uncertain tax positions. Of the total amount of unrecognized income tax benefits, $92 million would favorably affect FirstEnergy s effective tax rate upon recognition. The majority of items that would not have affected the effective tax rate would be purchase accounting adjustments to goodwill upon recognition. During the first nine months of 2007, there were no material changes to FirstEnergy s unrecognized tax benefits. As of September 30, 2007, the entire liability for uncertain tax positions is included in other non-current liabilities and changes to FirstEnergy s tax contingencies that are reasonably possible in the next twelve months are not material.

FIN 48 also requires companies to recognize 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 in accordance with FIN 48 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, consistent with its policy prior to implementing FIN 48. As of January 1, 2007, the net amount of interest accrued was $34 million. During the first nine months of 2007, there were no material changes to the amount of interest accrued.

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FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2006. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items are under appeal. The federal audit for years 2004 and 2005 began in June 2006 and is not expected to close before December 2007. The IRS began auditing the year 2006 in April 2006 under its Compliance Assurance Process experimental program, which is not expected to close before December 2007. 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.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 12). This transaction generated tax capital gains of approximately $752 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowances in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 3).

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) 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 September 30, 2007, outstanding guarantees and other assurances aggregated approximately $4.7 billion, consisting of parental guarantees $1.2 billion, subsidiaries guarantees $2.7 billion, surety bonds $0.1 billion and LOCs $0.7 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for subsidiary financings or refinancings 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 $0.6 billion (included in the $1.2 billion discussed above) as of September 30, 2007 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 or provision of an LOC may be required of the subsidiary. As of September 30, 2007, FirstEnergy s maximum exposure under these collateral provisions was $442 million.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $75 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

The Companies, with the exception of TE and JCP&L, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary s borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company.

Subsidiary Company	Parent Company	Borrowing Capacity (In millions)
OES Capital, Incorporated	OE	$ 170
Centerior Funding Corp.	CEI	200
Penn Power Funding LLC	Penn	25
Met-Ed Funding LLC	Met-Ed	80
Penelec Funding LLC	Penelec	75
		$ 550

FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6 million (subject to escalation) under the project s operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy has also provided an LOC ($27 million as of September 30, 2007), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. The LOC was reduced to $19 million on October 15, 2007.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 (see Note 12). FES has unconditionally and irrevocably guaranteed all of FGCO s obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust s undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES lease guaranty.

(B) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on FirstEnergy s earnings and competitive position to the extent that it 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. FirstEnergy estimates capital expenditures for environmental compliance of approximately $1.8 billion for 2007 through 2011.

FirstEnergy accrues environmental 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. Unasserted claims are reflected in FirstEnergy s determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006 alleging violations to various sections of the Clean Air Act. FirstEnergy has disputed those alleged

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violations based on its Clean Air Act permit, the Ohio SIP and other information provided at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss an appropriate compliance program and a disagreement regarding the opacity limit applicable to the common stack for Bay Shore Units 2, 3 and 4.

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_X reductions at FirstEnergy s facilities. The EPA s NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_X emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_X budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal Clean Air Act, alleging violations of air pollution laws at the Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Mansfield Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 16, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. FirstEnergy is currently studying PennFuture s complaint.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and fine particulate matter. In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the 8-hour ozone NAAQS in other states. CAIR allowed each affected state until 2006 to develop implementing regulations to achieve additional reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2). FirstEnergy s Michigan, Ohio and Pennsylvania fossil generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil generation facility will be subject to only a cap on NO_X emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_X emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_X cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which FirstEnergy operates affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NO_X emission caps under the EPA s CAIR program). Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the CAMR have been challenged in the United States Court of Appeals for the District of Columbia. FirstEnergy s future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which FirstEnergy operates affected facilities.

The model rules for both CAIR and CAMR contemplate an input-based methodology to allocate allowances to affected facilities. Under this approach, allowances would be allocated based on the amount of fuel consumed by the affected sources. FirstEnergy would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced, allowing new and non-emitting generating facilities (including renewables and nuclear) to be entitled to their proportionate share of the allowances. Consequently, FirstEnergy will be disadvantaged if these model rules were implemented as proposed because FirstEnergy s substantial reliance on non-emitting (largely nuclear) generation is not recognized under the input-based allocation.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. Pennsylvania s mercury regulation would deprive FES of mercury emission allowances that were to be allocated to the Mansfield Plant under the CAMR and that would otherwise be available for achieving FirstEnergy system-wide compliance. It is anticipated that compliance with these regulations, if approved by the EPA and implemented, would not require the addition of mercury controls at the Mansfield Plant, FirstEnergy s only Pennsylvania coal-fired power plant, until 2015, if at all.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or compliance orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which was owned at that time by OE and Penn, and is now owned by FGCO. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as the New Source Review, or NSR, cases.

On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation. This settlement agreement, which is in the form of a consent decree, was approved by the court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the Sammis NSR Litigation consent decree. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation settlement agreement are currently estimated to be $1.7 billion for 2007 through 2011 ($400 million of which is expected to be spent during 2007, with the largest portion of the remaining $1.3 billion expected to be spent in 2008 and 2009).

The Sammis NSR Litigation consent decree also requires FirstEnergy to spend up to $25 million toward environmentally beneficial projects, $14 million of which is satisfied by entering into 93 MW (or 23 MW if federal tax credits are not applicable) of wind energy purchased power agreements with a 20-year term. An initial 16 MW of the 93 MW consent decree obligation was satisfied during 2006.

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Climate Change

In December 1997, delegates to the United Nations climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Kyoto Protocol in 1998 but it failed to receive the two-thirds vote required for ratification by the United States Senate. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity the ratio of emissions to economic output by 18% through 2012. At the international level, efforts have begun to develop climate change agreements for post-2012 GHG reductions. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States. 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.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as air pollutants under the Clean Air Act. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the Clean Air Act to regulate air pollutants from those and other facilities. Also on April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, the EPA proposed to change the NSR regulations, on May 8, 2007, to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions could require significant capital and other expenditures. 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. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

On September 7, 2004, 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 large 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. On January 26, 2007, the federal Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to EPA for further rulemaking and eliminated the restoration option from EPA s regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment (BPJ) to minimize impacts on fish and shellfish from cooling water intake structures. FirstEnergy is evaluating various control options and their costs and effectiveness. Depending on the outcome of such studies, the EPA s further rulemaking and any action taken by the states exercising BPJ, the future cost of compliance with these standards may require material capital expenditures.

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Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA s evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of September 30, 2007, FirstEnergy had approximately $1.5 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley and Perry. As part of the application to the NRC to transfer the ownership of these nuclear facilities to NGC in 2005, FirstEnergy agreed to contribute another $80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a real rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy plans to seek for these facilities.

The Companies have been named as PRPs 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 PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2007, based on estimates of the total costs of cleanup, the Companies proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Total liabilities of approximately $89 million (JCP&L $60 million, TE $3 million, CEI $1 million, and FirstEnergy Corp. $25 million) have been accrued through September 30, 2007.

(C) 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. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey s electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. 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 arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted JCP&L s motion to decertify the class and denied plaintiffs motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision in July 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of JCP&L transformers in Red Bank, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L

renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court. FirstEnergy is defending this class action but is unable to predict the outcome of this matter. No liability has been accrued as of September 30, 2007.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy s service area. The U.S. Canada Power System Outage Task Force s final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy s Web site (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility s system. The final report contained 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy s implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy is also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

FirstEnergy companies also are defending four separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two of those cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these cases the individual complainants three in one case and four in the other sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Two other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc. (AEP), as well) for claims paid to insureds for damages allegedly arising as a result of the loss of power on August 14, 2003. A fifth case in which a carrier sought reimbursement for claims paid to insureds was voluntarily dismissed by the claimant in April 2007. A sixth case involving the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003 was dismissed. The four cases remaining were consolidated for hearing by the PUCO in an order dated March 7, 2006. In that order the PUCO also limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; and ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence. In response to a motion for rehearing filed by one of the claimants, the PUCO ruled on April 26, 2006 that the insurance company claimants, as insurers, may prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed amended complaints and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on January 8, 2008.

FirstEnergy is defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. Although FirstEnergy is unable to predict the impact of these proceedings, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a Demand for Information to FENOC following FENOC s reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration related to Davis-Besse. The NRC indicated that this information was needed for the NRC to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission s regulations. FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC s Demand for Information reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy s other nuclear plants safely and responsibly. The NRC held a public meeting on June 27, 2007 with FENOC to discuss FENOC s response to the Demand for Information. In follow-up discussions, FENOC was requested to provide supplemental information to clarify certain aspects of the Demand for Information response and provide additional details regarding plans to implement the commitments made therein. FENOC submitted this supplemental response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC s Office of Enforcement after it completes the key commitments embodied in the NRC s order. FENOC s compliance with these commitments is subject to future NRC review.

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.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs motion to amend their complaint which OE has opposed. On August 2, 2007, the Court denied the plaintiffs motion to amend their complaint. The plaintiffs have appealed the Court s denial of the motion for certification as a class action and motion to amend their complaint.

JCP&L s bargaining unit employees filed a grievance challenging JCP&L s 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. The arbitration panel provided additional rulings regarding damages during a September 2007 hearing and it is anticipated that he will issue a final order in late 2007. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 2005.

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.

11. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. Canada Power System Outage Task Force) regarding enhancements to regional reliability. In 2004, FirstEnergy completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training and emergency response preparedness recommended for completion in 2004. On July 14, 2004, NERC independently verified that FirstEnergy had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions noted by FirstEnergy, which exceptions are now essentially complete. FirstEnergy is proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new equipment or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability entities may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in JCP&L s service area in 2002 and 2003, the NJBPU had implemented reviews into JCP&L s service reliability. In 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by JCP&L and a timetable for completion and endorsed JCP&L s ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a stipulation that incorporates the final report of an SRM who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of JCP&L s Planning and Operations and Maintenance programs and practices. On February 11, 2005, JCP&L met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. JCP&L filed a comprehensive response to the NJBPU on July 14, 2006. JCP&L continues to file compliance reports reflecting activities associated with the MOU and stipulation.

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The EPACT served, among other things, partly to amend the Federal Power Act by adding a new Section 215, which requires that a new ERO establish and enforce reliability standards for the bulk-power system, subject to review by the FERC. Subsequently, the FERC certified NERC as the ERO, approved NERC s Compliance Monitoring and Enforcement Program and approved a set of reliability standards, which became mandatory and enforceable on June 18, 2007 with penalties and sanctions for noncompliance. The FERC also approved a delegation agreement between NERC and Reliability*First* Corporation, one of eight Regional Entities that carry out enforcement for NERC. All of FirstEnergy s facilities are located within the Reliability*First* region.

To date, FERC has approved 83 of the 107 reliability standards proposed by NERC. Nevertheless, the FERC has directed NERC to submit improvements to 56 of the 83 approved standards and has endorsed NERC s process for developing reliability standards and its associated work plan. On May 4, 2007, NERC submitted 24 proposed Violation Risk Factors that would operate as a system of weighting the risk to the power grid associated with a particular reliability standard violation. The FERC issued an order approving 22 of those factors on June 26, 2007. Further, NERC adopted eight cyber security standards and filed them with the FERC for approval. On December 11, 2006, the FERC Staff provided its preliminary assessment of the cyber security standards and cited various deficiencies in the proposed standards. Numerous parties, including FirstEnergy, provided comments on the preliminary assessment. The standards remain pending before the FERC. Separately, on July 20, 2007, the FERC issued a NOPR proposing to adopt eight related Critical Infrastructure Protection Reliability Standards. On October 5, 2007, numerous parties, including FirstEnergy, provided comments on the proposed Critical Infrastructure Protection standards. These standards, and FirstEnergy s comments thereon, are pending before FERC.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, based upon a review of the FERC s guidance to NERC in its March 16, 2007 Final Rule on Mandatory Reliability Standards, it appears that the FERC may eventually adopt stricter standards than those just approved. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for its bulk power system in the future, it could have a material adverse effect on FirstEnergy s and its subsidiaries financial condition, results of operations and cash flows.

On April 18-20, 2007, Reliability*First* performed a routine compliance audit of FirstEnergy s bulk-power system within the Midwest ISO region and found FirstEnergy to be in full compliance with all audited reliability standards. Similarly, Reliability*First* has scheduled a compliance audit of FirstEnergy s bulk-power system within the PJM region in 2008. FirstEnergy does not expect any material adverse impact to its financial condition as a result of these audits.

(B) OHIO

On September 9, 2005, the Ohio Companies filed their RCP with the PUCO. The filing included a stipulation and supplemental stipulation with several parties agreeing to the provisions set forth in the plan. On January 4, 2006, the PUCO issued an order which approved the stipulation on the RCP after clarifying certain provisions. Several parties subsequently filed appeals to the Supreme Court of Ohio in connection with certain portions of the RCP approved by the PUCO. In its order, the PUCO authorized the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs, all such costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a 25-year period through distribution rates, which was expected to begin on January 1, 2009 for OE and TE, and approximately May 2009 for CEI. Through September 30, 2007, the deferred fuel costs, including interest, were $89 million, $61 million and $26 million for OE, CEI and TE, respectively.

On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated certain provisions of the Ohio Revised Code by permitting the Ohio Companies to collect deferred increased fuel costs through future

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distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses because fuel costs are a component of generation service, not distribution service, and because the Court concluded the PUCO did not address whether the deferral of fuel costs was anticompetitive. The Court remanded the matter to the PUCO for further consideration consistent with the Court s Opinion on this issue and affirmed the PUCO s Order in all other respects. On September 7, 2007, the Ohio Companies filed a Motion for Reconsideration with the Court. On September 10, 2007 the Ohio Companies filed an Application with the PUCO that requests the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. The Ohio Companies requested the riders become effective in October 2007 and end in December 2008, subject to reconciliation which is expected to continue through the first quarter of 2009. This matter is currently pending before the PUCO. Although unable to predict the ultimate outcome of this matter, the Ohio Companies intend to continue deferring the fuel costs pursuant to the RCP, pending the Court s disposition of the Motion for Reconsideration and the PUCO s action with respect to the Ohio Companies Application.

On August 31, 2005, the PUCO approved a rider recovery mechanism through which the Ohio Companies may recover all MISO transmission and ancillary service related costs incurred during each year ending June 30. Pursuant to the PUCO s order, the Ohio Companies, on May 1, 2007, filed revised riders, which became effective on July 1, 2007. The revised riders represent an increase over the amounts collected through the 2006 riders of approximately $64 million annually. If it is subsequently determined by the PUCO that adjustments to the rider as filed are necessary, such adjustments, with carrying costs, will be incorporated into the 2008 transmission rider filing.

On May 8, 2007, the Ohio Companies filed with the PUCO a notice of intent to file for an increase in electric distribution rates. The Ohio Companies filed the application and rate request with the PUCO on June 7, 2007. The requested increase is expected to be more than offset by the elimination or reduction of transition charges at the time the rates go into effect and would result in lowering the overall non-generation portion of the bill for most Ohio customers. The distribution rate increases reflect capital expenditures since the Ohio Companies last distribution rate proceedings, increases in operating and maintenance expenses and recovery of regulatory assets created by deferrals that were approved in prior cases. On August 6, 2007, the Ohio Companies updated their filing supporting a distribution rate increase of $332 million to the PUCO to establish the test period data that will be used as the basis for setting rates in that proceeding. The PUCO Staff is expected to issue its report in the case in the fourth quarter of 2007 with evidentiary hearings to follow in early 2008. The PUCO order is expected to be issued in the second quarter of 2008. The new rates would become effective January 1, 2009 for OE and TE, and approximately May 2009 for CEI.

On July 10, 2007, the Ohio Companies filed an application with the PUCO requesting approval of a comprehensive supply plan for providing generation service to customers who do not purchase electricity from an alternative supplier, beginning January 1, 2009. The proposed competitive bidding process would average the results of multiple bidding sessions conducted at different times during the year. The final price per kilowatt-hour would reflect an average of the prices resulting from all bids. In their filing, the Ohio Companies offered two alternatives for structuring the bids, either by customer class or a slice-of-system approach. The proposal provides the PUCO with an option to phase in generation price increases for residential tariff groups who would experience a change in their average total price of 15 percent or more. The PUCO held a technical conference on August 16, 2007 regarding the filing. Comments by intervenors in the case were filed on September 5, 2007. The PUCO Staff filed comments on September 21, 2007. Parties filed reply comments on October 12, 2007. The Ohio Companies requested that the PUCO issue an order by November 1, 2007, to provide sufficient time to conduct the bidding process.

On September 25, 2007, the Ohio Governor s proposed energy plan was officially introduced into the Ohio Senate. The bill proposes to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create GHG emissions reporting and carbon control planning requirements. The bill also proposes to move to a hybrid system for determining rates for PLR service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive market for retail electricity. The Senate Energy & Public Utilities Committee has been conducting hearings on the bill and receiving testimony from interested parties, including the Governor s Energy Advisor, the Chairman of the PUCO, consumer groups, utility executives and others. Several proposed amendments to the bill have been submitted, including those from Ohio s investor-owned electric utilities. A substitute version of the bill, which incorporated certain of the proposed amendments, was introduced into the Senate Energy & Public Utilities Committee on October 25, 2007. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on its operations or those of the Ohio Companies.

(C) PENNSYLVANIA

Met-Ed and Penelec have been purchasing a portion of their PLR requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Under these agreements, FES retained the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by Met-Ed and Penelec. The FES agreements have reduced Met-Ed s and Penelec s exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR capacity and energy requirements during the term of these agreements with FES.

On September 26, 2006, Met-Ed and Penelec successfully conducted a competitive RFP for a portion of their PLR obligation for the period December 1, 2006 through December 31, 2008. FES was one of the successful bidders in that RFP process and on September 26, 2006 entered into a supplier master agreement to supply a certain portion of Met-Ed s and Penelec s PLR requirements at market prices that were substantially higher than the fixed price in the partial requirements agreements.

Based on the outcome of the 2006 comprehensive transition rate filing, as described below, Met-Ed, Penelec and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days notice prior to the end of the year. The restated agreement also allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy thus sold to the extent needed for Met-Ed and Penelec to satisfy their PLR obligations. The parties also have separately terminated the supplier master agreements in connection with the restatement of the partial requirements agreement. Accordingly, the energy that would have been supplied under the supplier master agreement will now be provided under the restated partial requirements agreement. The fixed price under the restated agreement is expected to remain below wholesale market prices during the term of the agreement.

If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company s credit profile would no longer be expected to support an investment grade rating for its fixed income securities. Based on the PPUC s January 11, 2007 order described below, if FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed s and Penelec s generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC.

Met-Ed and Penelec made a comprehensive transition rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If Met-Ed s and Penelec s preferred approach involving accounting deferrals had been approved, annual revenues would have increased by $216 million and $157 million, respectively. That filing included, among other things, a request to charge customers for an increasing amount of market-priced power procured through a CBP as the amount of supply provided under the then existing FES agreement was to be phased out. Met-Ed and Penelec also requested approval of a January 12, 2005 petition for the deferral of transmission-related costs incurred during 2006. In this rate filing, Met-Ed and

Penelec also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider. Changes in the recovery of NUG expenses and the recovery of Met-Ed s non-NUG stranded costs were also included in the filing. On May 4, 2006, the PPUC consolidated the remand of the FirstEnergy and GPU merger proceeding, related to the quantification and allocation of merger savings, with the comprehensive transition rate filing case.

The PPUC entered its Opinion and Order in the comprehensive rate filing proceeding on January 11, 2007. The order approved the recovery of transmission costs, including the transmission-related deferral for January 1, 2006 through January 10, 2007, when new transmission rates were effective, and determined that no merger savings from prior years should be considered in determining customers rates. The request for increases in generation supply rates was denied as were the requested changes in NUG expense recovery and Met-Ed s non-NUG stranded costs. The order decreased Met-Ed s and Penelec s distribution rates by $80 million and $19 million, respectively. These decreases were offset by the increases allowed for the recovery of transmission expenses and the transmission deferral. Met-Ed s and Penelec s request for recovery of Saxton decommissioning costs was granted and, in January 2007, Met-Ed and Penelec recognized income of $15 million and $12 million, respectively, to establish regulatory assets for those previously expensed decommissioning costs. Overall rates increased by 5.0% for Met-Ed ($59 million) and 4.5% for Penelec ($50 million). Met-Ed and Penelec filed a Petition for Reconsideration on January 26, 2007 on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission (including congestion), transmission deferrals and rate design issues. On February 8, 2007, the PPUC entered an order granting Met-Ed s, Penelec s and the other parties petitions for procedural purposes. Due to that ruling, the period for appeals to the Commonwealth Court of Pennsylvania was tolled until 30 days after the PPUC entered a subsequent order ruling on the substantive issues raised in the petitions. On March 1, 2007, the PPUC issued three orders: (1) a tentative order regarding the reconsideration by the PPUC of its own order; (2) an order denying the Petitions for Reconsideration of Met-Ed, Penelec and the OCA and denying in part and accepting in part the MEIUG s and PICA s Petition for Reconsideration; and (3) an order approving the compliance filing. Comments to the PPUC for reconsideration of its order were filed on March 8, 2007, and the PPUC ruled on the reconsideration on April 13, 2007, making minor changes to rate design as agreed upon by Met-Ed, Penelec and certain other parties.

On March 30, 2007, MEIUG and PICA filed a Petition for Review with the Commonwealth Court of Pennsylvania asking the court to review the PPUC s determination on transmission (including congestion) and the transmission deferral. Met-Ed and Penelec filed a Petition for Review on April 13, 2007 on the issues of consolidated tax savings and the requested generation rate increase. The OCA filed its Petition for Review on April 13, 2007, on the issues of transmission (including congestion) and recovery of universal service costs from only the residential rate class. On June 19, 2007, initial briefs were filed and responsive briefs were filed through September 21, 2007. Reply briefs were filed on October 5, 2007. Oral arguments are expected to take place in late 2007 or early 2008. If Met-Ed and Penelec do not prevail on the issue of congestion, it could have a material adverse effect on the financial condition and results of operations of Met-Ed, Penelec and FirstEnergy.

As of September 30, 2007, Met-Ed s and Penelec s unrecovered regulatory deferrals pursuant to the 2006 comprehensive transition rate case, the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $496 million and $58 million, respectively. During the PPUC s annual audit of Met-Ed s and Penelec s NUG stranded cost balances in 2006, it noted a modification to the NUG purchased power stranded cost accounting methodology made by Met-Ed and Penelec. On August 18, 2006, a PPUC Order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of this PPUC order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition were held in February 2007 and briefing was completed on March 28, 2007. The ALJ s initial decision was issued on May 3, 2007 and denied Met-Ed s and Penelec s request to modify their NUG stranded cost accounting methodology. The companies filed exceptions to the initial decision on May 23, 2007 and replies to those exceptions were filed on June 4, 2007. It is not known when the PPUC may issue a final decision in this matter.

On May 2, 2007, Penn filed a plan with the PPUC for the procurement of PLR supply from June 2008 through May 2011. The filing proposes multiple, competitive RFPs with staggered delivery periods for fixed-price, tranche-based, pay as bid PLR supply to the residential and commercial classes. The proposal phases out existing promotional rates and eliminates the declining block and the demand components on generation rates for residential and commercial customers. The industrial class PLR service will be provided through an hourly-priced service provided by Penn. Quarterly reconciliation of the differences between the costs of supply and revenues from customers is also proposed. On September 28, 2007, Penn filed a Joint Petition for Settlement resolving all but one issue in the case. Briefs were also filed on September 28, 2007 on the unresolved issue of incremental uncollectible accounts expense. The settlement is either supported, or not opposed, by all parties. The PPUC is expected to act on the settlement and the unresolved issue in late November or early December 2007 for the initial RFP to take place in January 2008.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation programs to meet demand growth, a requirement that electric distribution companies acquire power that results in the lowest reasonable rate on a long-term basis, the utilization of micro-grids and an optional three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company s transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. The final form of any legislation arising from the special legislative session is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

(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 and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of September 30, 2007, the accumulated deferred cost balance totaled approximately $330 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the Staff circulated a revised draft proposal to interested stakeholders. Another revised draft was circulated by the NJBPU Staff on February 8, 2007.

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 EMP is to be developed with involvement of the Governor s Office and the Governor s Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments. In October 2006, the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of New Jersey s electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Maintain unit prices for electricity to no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to obtain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. EMP working groups addressing (1) energy efficiency and demand response, (2) renewables, (3) reliability, and (4) pricing issues have completed their assigned tasks of data gathering and analysis and have provided reports to the EMP Committee. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected later in 2007. A final draft of the EMP is expected to be presented to the Governor in late 2007. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on its operations or those of JCP&L.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments which were due on September 26, 2007. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on its operations or those of JCP&L.

(E) FERC MATTERS

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in the fourth quarter of 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas & Electric Company (BG&E) and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. Hearings were held and numerous parties appeared and litigated various issues; including AEP, which filed in opposition proposing to create a postage stamp rate for high voltage transmission facilities across PJM. At the conclusion of the hearings, the ALJ issued an initial decision adopting the FERC Trial Staff s position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. Numerous parties, including FirstEnergy, submitted briefs opposing the ALJ s decision and recommendations. On April 19, 2007, the FERC issued an order rejecting the ALJ s findings and recommendations in nearly every respect. The FERC found that the PJM transmission owners existing license plate 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, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be socialized throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a beneficiary pays basis. Nevertheless, the FERC found that PJM s current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM s tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC s April 19, 2007 Order. Subsequently, FirstEnergy and other parties filed pleadings opposing the requests for rehearing. The FERC s Orders on PJM rate design, if sustained on rehearing and appeal, will prevent the allocation of the cost of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC s decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce future transmission costs shifting to the JCP&L, Met-Ed and Penelec zones.

New FERC Transmission Rate Design Filings

On August 1, 2007, a number of filings were made with the FERC by transmission owning utilities in the MISO and PJM footprint that could affect the transmission rates paid by FirstEnergy s operating companies and FES.

FirstEnergy joined in a filing made by the MISO transmission owners that would maintain the existing license plate rates for transmission service within MISO provided over existing transmission facilities. FirstEnergy also joined in a filing made by both the MISO and PJM transmission owners proposing to continue the elimination of transmission rates associated with service over existing transmission facilities between MISO and PJM. If adopted by the FERC, these filings would not affect the rates charged to load-serving FirstEnergy affiliates for transmission service over existing transmission facilities. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint be maintained (known as the RECB Process). Each of these filings was supported by the majority of transmission owners in either MISO or PJM, as applicable.

The Midwest Stand-Alone Transmission Companies made a filing under Section 205 of the Federal Power Act requesting that 100% of the cost of new qualifying 345 kV and higher transmission facilities be spread throughout the entire MISO footprint. Further, Indianapolis Power and Light Company separately moved the FERC to reopen the record to address the cost allocation for the RECB Process. If either proposal is adopted by the FERC, it could shift a greater portion of the cost of new 345 kV and higher transmission facilities to the FirstEnergy footprint in MISO, and increase the transmission rates paid by load-serving FirstEnergy affiliates in MISO.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM SuperRegion that regionalizes the cost of new and existing transmission facilities operated at voltages of 345 kV and above. Lower voltage facilities would continue to be recovered in the host utility transmission rate zone through a license plate rate. AEP requests a refund effective October 1, 2007, or alternatively, February 1, 2008. The effect of this proposal, if adopted by FERC, would be to shift significant costs to the FirstEnergy zones in MISO and PJM. FirstEnergy believes that most of these costs would ultimately be recoverable in retail rates. On October 12, 2007, BG&E filed a motion to dismiss AEP s complaint. On October 16, 2007, the Organization of MISO States filed comments urging the FERC to dismiss AEP s complaint. Interventions and protests to AEP s complaint and answers to BG&E s motion to dismiss were due October 29, 2007. FirstEnergy and other transmission owners filed protests to AEP s complaint and support for BG&E s motion to dismiss. AEP has asked for consolidation of its complaint with the cases above, and FirstEnergy expects it to be resolved on the same timeline as those cases.

Any increase in rates charged for transmission service to FirstEnergy affiliates is dependent upon the outcome of these proceedings at FERC. All or some of these proceedings may be consolidated by the FERC and set for hearing. The outcome of these cases cannot be predicted. Any material adverse impact on FirstEnergy would depend upon the ability of the load-serving FirstEnergy affiliates to recover increased transmission costs in their retail rates. FirstEnergy believes that current retail rate mechanisms in place for PLR service for the Ohio Companies and for Met-Ed and Penelec would permit them to pass through increased transmission charges in their retail rates. Increased transmission charges in the JCP&L and Penn transmission zones would be the responsibility of competitive electric retail suppliers, including FES.

MISO Ancillary Services Market and Balancing Area Consolidation Filing

MISO made a filing on September 14, 2007 to establish Ancillary Services markets for regulation, spinning and supplemental reserves, to consolidate the existing 24 balancing areas within the MISO footprint, and to establish MISO as the NERC registered balancing authority for the region. An effective date of June 1, 2008 was requested in the filing.

MISO s previous filing to establish an Ancillary Services market was rejected without prejudice by FERC on June 22, 2007, subject to MISO making certain modifications in its filing. FirstEnergy believes that MISO s September 14 filing generally addresses the FERC s directives. FirstEnergy supports the proposal to establish markets for Ancillary Services and consolidate existing balancing areas, but filed objections on specific aspects of the MISO proposal. Interventions and protests to MISO s filing were made with FERC on October 15, 2007.

Order No. 890 on Open Access Transmission Tariffs

On February 16, 2007, the FERC issued a final rule (Order No. 890) that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule became effective on May 14, 2007. MISO, PJM and ATSI will be filing revised tariffs to comply with the FERC s order. MISO, PJM and ATSI submitted tariff filings to the FERC on October 11, 2007. As a market participant in both MISO and PJM, FirstEnergy will conform its business practices to each respective revised tariff.

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12. LEASES

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately $1.329 billion (net after-tax proceeds of approximately $1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of $1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases. FES has unconditionally and irrevocably guaranteed all of FGCO s obligations under each of the leases. FES registration obligations under the registration rights agreement applicable to the $1.135 billion principal amount of pass through certificates issued in connection with the transaction were satisfied in September 2007, at which time the transaction was classified as an operating lease under GAAP for FES and FirstEnergy. This transaction generated tax capital gains of approximately $752 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowances in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 3).

The future minimum lease payments associated with the recently completed Bruce Mansfield Unit 1 sale and leaseback transaction as of September 30, 2007 are as follows (in millions):

2007	$ 44
2008	89
2009	89
2010	89
2011	89
Years thereafter	2,286
Total minimum lease payments	$ 2,686

13. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 157 Fair Value Measurements

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

SFAS 159 The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. This Statement requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company s choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet.

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This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157 and SFAS 107. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

EITF 06-11 Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards

In June 2007, the FASB released EITF 06-11, which provides guidance on the appropriate accounting for income tax benefits related to dividends earned on nonvested share units that are charged to retained earnings under SFAS 123(R). The consensus requires that an entity recognize the realized tax benefit associated with the dividends on nonvested shares as an increase to APIC. This amount should be included in the APIC pool, which is to be used when an entity s estimate of forfeitures increases or actual forfeitures exceed its estimates, at which time the tax benefits in the APIC pool would be reclassified to the income statement. The consensus is effective for income tax benefits of dividends declared during fiscal years beginning after December 15, 2007. EITF 06-11 is not expected to have a material effect on FirstEnergy s financial statements.

FSP FIN 39-1 Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, which permits an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement as the derivative instruments. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying the guidance in this FSP should be recognized as a retrospective change in accounting principle for all financial statements presented. FirstEnergy is currently evaluating the impact of this FSP on its financial statements but it is not expected to have a material impact.

14. SEGMENT INFORMATION

Effective January 1, 2007, FirstEnergy has three reportable operating segments: energy delivery services, competitive energy services and Ohio transitional generation services. None of the aggregate Other segments individually meet the criteria to be considered a reportable segment. The energy delivery services segment consists of regulated transmission and distribution operations, including transition cost recovery, and PLR generation service for FirstEnergy s Pennsylvania and New Jersey electric utility subsidiaries. The competitive energy services segment primarily consists of unregulated generation and commodity operations, including competitive electric sales, and generation sales to affiliated electric utilities. The Ohio transitional generation services segment represents PLR generation service by FirstEnergy s Ohio electric utility subsidiaries. Other primarily consists of telecommunications services and other non-core assets. The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as reportable operating segments.

The energy delivery services segment designs, constructs, operates and maintains FirstEnergy s regulated transmission and distribution systems and is responsible for the regulated generation commodity operations of FirstEnergy s Pennsylvania and New Jersey electric utility subsidiaries. Its revenues are primarily derived from the delivery of electricity, cost recovery of regulatory assets and PLR electric generation sales to non-shopping customers in its Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES under partial requirements purchased power agreements and non-affiliated power suppliers as well as the net PJM transmission expenses related to the delivery of that generation load.

The competitive energy services segment supplies electric power to its electric utility affiliates and competitive electric sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. The segment owns or leases and operates FirstEnergy s generating facilities and purchases electricity to meet its sales obligations. The segment s net income is primarily derived from the affiliated company power sales and the 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 electricity to the segment s customers. The segment s internal revenues represent the affiliated company power sales.

The Ohio transitional generation services segment represents the regulated generation operations of FirstEnergy s Ohio electric utility subsidiaries. Its revenues are primarily derived from electric generation sales to non-shopping customers under the PLR obligations of the Ohio Companies. Its results reflect the purchase of electric generation from the competitive energy services segment through full requirements PSA arrangements, the deferral and amortization of certain fuel costs authorized for recovery by the energy delivery services segment and the net MISO transmission revenues and expenses related to the delivery of its generation load. This segment s total assets consist of accounts receivable for generation revenues from retail customers.

Segment reporting in 2006 has been revised to conform to the current year business segment organization and operations. Changes in the current year operations reporting and revised 2006 segment reporting primarily reflect the transfer from FES to the regulated utilities of the responsibility for obtaining PLR generation for the utilities non-shopping customers. This reflects FirstEnergy s alignment of its business units to accommodate its retail strategy and participation in competitive electricity marketplaces in Ohio, Pennsylvania and New Jersey. The differentiation of the regulated generation commodity operations between the two regulated business segments recognizes that generation sourcing for the Ohio Companies is currently in a transitional state through 2008 as compared to the segregated commodity sourcing of their Pennsylvania and New Jersey utility affiliates. The results of the energy delivery services and the Ohio transitional generation services segments now include their electric generation revenues and the corresponding generation commodity costs under affiliated and non-affiliated purchased power arrangements and related net retail PJM/MISO transmission expenses associated with serving electricity load in their respective franchise areas.

FSG completed the sale of its five remaining subsidiaries in 2006. Its assets and results for 2006 are combined in the Other segments in this report, as the remaining business does not meet the criteria of a reportable segment. Interest expense on holding company debt and corporate support services revenues and expenses are included in Reconciling Adjustments.

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Segment Financial Information

Three Months Ended	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Reconciling Adjustments	Consolidated
			(In millions)			
September 30, 2007						
External revenues	$ 2,520	$ 370	$ 723	$ 9	$ 19	$ 3,641
Internal revenues		806			(806)	
Total revenues	2,520	1,176	723	9	(787)	3,641
Depreciation and amortization	299	51	(16)	1	8	343
Investment income	58	5		1	(34)	30
Net interest charges	117	39		1	37	194
Income taxes	175	99	11	(2)	(10)	273
Net income	269	148	16	6	(26)	413
Total assets	23,308	7,182	268	232	663	31,653
Total goodwill	5,585	24				5,609
Property additions	209	199		1	21	430
September 30, 2006						
External revenues	$ 2,306	$ 353	$ 690	$ 24	$ (9)	$ 3,364
Internal revenues		762			(762)	
Total revenues	2,306	1,115	690	24	(771)	3,364
Depreciation and amortization	227	49	(40)	1	6	243
Investment income	80	18			(52)	46
Net interest charges	107	49		2	22	180
Income taxes	187	112	18	(14)	(30)	273
Income from continuing operations	280	169	27	25	(49)	452
Discontinued operations				2		2
Net income	280	169	27	27	(49)	454
Total assets	23,940	6,822	240	321	839	32,162
Total goodwill	5,911	24				5,935
Property additions	119	126			6	251
Nine Months Ended						
September 30, 2007						
External revenues	$ 6,655	$ 1,089	$ 1,968	$ 29	$ (18)	$ 9,723
Internal revenues		2,210			(2,210)	
Total revenues	6,655	3,299	1,968	29	(2,228)	9,723
Depreciation and amortization	767	153	(80)	3	20	863
Investment income	190	13	1	1	(112)	93
Net interest charges	340	131	1	3	97	572
Income taxes	464	259	46		(74)	695
Net income	695	388	69	13	(124)	1,041
Total assets	23,308	7,182	268	232	663	31,653
Total goodwill	5,585	24				5,609
Property additions	609	462		4	52	1,127
September 30, 2006						
External revenues	$ 5,876	$ 1,077	$ 1,808	$ 92	$ (32)	$ 8,821
Internal revenues	14	1,997			(2,011)	
Total revenues	5,890	3,074	1,808	92	(2,043)	8,821
Depreciation and amortization	657	143	(89)	3	17	731
Investment income	244	35		1	(160)	120
Net interest charges	308	139	1	5	60	513
Income taxes	468	201	58	(17)	(85)	625

Income from continuing operations	702	302	88	30	(139)	983
Discontinued operations				(4)		(4)
Net income	702	302	88	26	(139)	979
Total assets	23,940	6,822	240	321	839	32,162
Total goodwill	5,911	24				5,935
Property additions	489	473			28	990

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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.

15. SUPPLEMENTAL GUARANTOR INFORMATION

As discussed in Note 12, on July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO s obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust s undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES lease guaranty.

The consolidating statements of income for the three months and nine months ended September 30, 2007 and 2006, consolidating balance sheets as of September 30, 2007 and December 31, 2006 and condensed consolidating statements of cash flows for the nine months ended September 30, 2007 and 2006 for FES (parent), 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. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and reflect the consolidating entries associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

(Unaudited)

For the Three Months Ended September 30, 2007	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,180,449	$ 496,204	$ 280,072	$ (785,817)	$ 1,170,908
EXPENSES:					
Fuel	10,944	261,759	29,083		301,786
Purchased power from non-affiliates	228,755				228,755
Purchased power from affiliates	774,873	57,927	15,525	(785,817)	62,508
Other operating expenses	41,828	75,985	117,220		235,033
Provision for depreciation	650	24,669	23,181		48,500
General taxes	5,406	11,788	5,048		22,242
Total expenses	1,062,456	432,128	190,057	(785,817)	898,824
OPERATING INCOME	117,993	64,076	90,015		272,084
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	82,870	2,375	3,935	(76,525)	12,655
Interest expense to affiliates	(676)	(4,769)	(4,196)		(9,641)
Interest expense other	(808)	(21,274)	(9,712)		(31,794)
Capitalized interest	9	3,889	1,233		5,131
Total other income (expense)	81,395	(19,779)	(8,740)	(76,525)	(23,649)
INCOME BEFORE INCOME TAXES	199,388	44,297	81,275	(76,525)	248,435
INCOME TAXES	44,624	19,850	29,197		93,671
NET INCOME	$ 154,764	$ 24,447	$ 52,078	$ (76,525)	$ 154,764

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

(Unaudited)

For the Three Months Ended September 30, 2006	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,120,844	$ 466,628	$ 246,039	$ (723,931)	$ 1,109,580
EXPENSES:					
Fuel	12,632	273,398	29,491		315,521
Purchased power from non-affiliates	173,620				173,620
Purchased power from affiliates	711,298	52,062	16,218	(723,931)	55,647
Other operating expenses	42,115	48,728	107,873		198,716
Provision for depreciation	456	24,656	21,782		46,894
General taxes	3,223	8,931	5,455		17,609
Total expenses	943,344	407,775	180,819	(723,931)	808,007
OPERATING INCOME	177,500	58,853	65,220		301,573
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	69,102	1,694	18,089	(61,223)	27,662
Interest expense to affiliates		(29,988)	(11,428)		(41,416)
Interest expense other	(207)	(2,749)	(4,958)		(7,914)
Capitalized interest	5	1,217	1,167		2,389
Total other income (expense)	68,900	(29,826)	2,870	(61,223)	(19,279)
INCOME BEFORE INCOME TAXES	246,400	29,027	68,090	(61,223)	282,294
INCOME TAXES	70,281	10,134	25,760		106,175
NET INCOME	$ 176,119	$ 18,893	$ 42,330	$ (61,223)	$ 176,119

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

(Unaudited)

For the Nine Months Ended September 30, 2007	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 3,274,694	$ 1,501,112	$ 793,255	$ (2,311,129)	$ 3,257,932
EXPENSES:					
Fuel	20,824	698,643	84,734		804,201
Purchased power from non-affiliates	577,831				577,831
Purchased power from affiliates	2,290,305	176,654	53,746	(2,311,129)	209,576
Other operating expenses	123,596	240,774	367,404		731,774
Provision for depreciation	1,572	74,844	68,614		145,030
General taxes	15,942	31,406	17,522		64,870
Total expenses	3,030,070	1,222,321	592,020	(2,311,129)	2,533,282
OPERATING INCOME	244,624	278,791	201,235		724,650
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	271,599	2,669	13,350	(239,862)	47,756
Interest expense to affiliates	(676)	(47,090)	(14,138)		(61,904)
Interest expense other	(7,966)	(34,150)	(28,729)		(70,845)
Capitalized interest	20	9,044	3,699		12,763
Total other income (expense)	262,977	(69,527)	(25,818)	(239,862)	(72,230)
INCOME BEFORE INCOME TAXES	507,601	209,264	175,417	(239,862)	652,420
INCOME TAXES	98,917	82,031	62,788		243,736
NET INCOME	$ 408,684	$ 127,233	$ 112,629	$ (239,862)	$ 408,684

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING STATEMENTS OF INCOME

(Unaudited)

For the Nine Months Ended September 30, 2006	FES	FGCO	NGC *(In thousands)*	Eliminations	Consolidated
REVENUES	$ 3,071,970	$ 1,336,076	$ 797,967	$ (2,145,891)	$ 3,060,122
EXPENSES:					
Fuel	16,650	752,229	76,034		844,913
Purchased power from non-affiliates	477,249				477,249
Purchased power from affiliates	2,143,509	141,974	49,106	(2,145,891)	188,698
Other operating expenses	149,042	204,282	421,443		774,767
Provision for depreciation	1,314	72,778	61,322		135,414
General taxes	9,268	29,536	16,746		55,550
Total expenses	2,797,032	1,200,799	624,651	(2,145,891)	2,476,591
OPERATING INCOME	274,938	135,277	173,316		583,531
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	146,375	(3,052)	35,518	(133,998)	44,843
Interest expense to affiliates	(241)	(87,318)	(35,105)		(122,664)
Interest expense other	(564)	(5,650)	(11,666)		(17,880)
Capitalized interest	(3)	3,290	5,411		8,698
Total other income (expense)	145,567	(92,730)	(5,842)	(133,998)	(87,003)
INCOME BEFORE INCOME TAXES	420,505	42,547	167,474	(133,998)	496,528
INCOME TAXES	108,549	13,296	62,727		184,572
NET INCOME	$ 311,956	$ 29,251	$ 104,747	$ (133,998)	$ 311,956

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING BALANCE SHEETS

(Unaudited)

As of September 30, 2007	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 2	$	$	$	$ 2
Receivables-					
Customers	144,443				144,443
Associated companies	282,118	169,108	113,936	(279,700)	285,462
Other	4,862	554			5,416
Notes receivable from associated companies		242,612			242,612
Materials and supplies, at average cost	195	224,149	216,722		441,066
Prepayments and other	67,892	13,693	2,240		83,825
	499,512	650,116	332,898	(279,700)	1,202,826
PROPERTY, PLANT AND EQUIPMENT:					
In service	25,171	5,023,255	3,530,969	(395,817)	8,183,578
Less Accumulated provision for depreciation	6,807	2,539,192	1,476,051	(169,154)	3,852,896
	18,364	2,484,063	2,054,918	(226,663)	4,330,682
Construction work in progress	1,034	414,243	181,602		596,879
	19,398	2,898,306	2,236,520	(226,663)	4,927,561
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,342,083		1,342,083
Long-term notes receivable from associated companies			62,900		62,900
Investment in associated companies	2,462,960			(2,462,960)	
Other	5,315	34,447	202		39,964
	2,468,275	34,447	1,405,185	(2,462,960)	1,444,947
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	28,756	403,890		(192,464)	240,182
Goodwill	24,248				24,248
Property taxes		20,946	23,165		44,111
Pension assets	1,154	8,295			9,449
Other	33,049	32,477	5,112		70,638
	87,207	465,608	28,277	(192,464)	388,628
	$ 3,074,392	$ 4,048,477	$ 4,002,880	$ (3,161,787)	$ 7,963,962
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$	$ 624,517	$ 861,265	$ (16,061)	$ 1,469,721
Notes payable-					
Associated companies	223,942		13,128		237,070
Other					
Accounts payable-					
Associated companies	279,976	158,500	273,919	(279,700)	432,695

Other	65,782	112,038			177,820
Accrued taxes	44,995	461,635	30,430		537,060
Other	60,252	59,770	9,731	33,486	163,239
	674,947	1,416,460	1,188,473	(262,275)	3,017,605
CAPITALIZATION:					
Common stockholder s equity	2,369,019	905,100	1,557,860	(2,462,960)	2,369,019
Long-term debt		1,575,653	242,400	(1,312,857)	505,196
	2,369,019	2,480,753	1,800,260	(3,775,817)	2,874,215
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				1,068,769	1,068,769
Accumulated deferred income taxes			192,464	(192,464)	
Accumulated deferred investment tax credits		36,764	25,511		62,275
Asset retirement obligations		24,350	773,007		797,357
Retirement benefits	7,843	45,662			53,505
Property taxes		21,268	23,165		44,433
Other	22,583	23,220			45,803
	30,426	151,264	1,014,147	876,305	2,072,142
	$ 3,074,392	$ 4,048,477	$ 4,002,880	$ (3,161,787)	$ 7,963,962

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FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATING BALANCE SHEETS

(Unaudited)

As of December 31, 2006	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 2	$	$	$	$ 2
Receivables-					
Customers	129,843				129,843
Associated companies	201,281	160,965	69,751	(196,465)	235,532
Other	2,383	1,702			4,085
Notes receivable from associated companies	460,023		292,896		752,919
Materials and supplies, at average cost	195	238,936	221,108		460,239
Prepayments and other	45,314	10,389	1,843		57,546
	839,041	411,992	585,598	(196,465)	1,640,166
PROPERTY, PLANT AND EQUIPMENT:					
In service	16,261	4,960,453	3,378,630		8,355,344
Less Accumulated provision for depreciation	5,738	2,477,004	1,335,526		3,818,268
	10,523	2,483,449	2,043,104		4,537,076
Construction work in progress	345	170,063	169,478		339,886
	10,868	2,653,512	2,212,582		4,876,962
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,238,272		1,238,272
Long-term notes receivable from associated companies			62,900		62,900
Investment in associated companies	1,471,184			(1,471,184)	
Other	6,474	65,833	202		72,509
	1,477,658	65,833	1,301,374	(1,471,184)	1,373,681
DEFERRED CHARGES AND OTHER ASSETS:					
Goodwill	24,248				24,248
Property taxes		20,946	23,165		44,111
Accumulated deferred income taxes	32,939			(32,939)	
Other	23,544	11,542	4,753		39,839
	80,731	32,488	27,918	(32,939)	108,198
	$ 2,408,298	$ 3,163,825	$ 4,127,472	$ (1,700,588)	$ 7,999,007
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$	$ 608,395	$ 861,265	$	$ 1,469,660
Notes payable to associated companies		1,022,197			1,022,197
Accounts payable-					
Associated companies	375,328	11,964	365,222	(196,465)	556,049
Other	32,864	103,767			136,631
Accrued taxes	54,537	32,028	26,666		113,231
Other	49,906	41,401	9,634		100,941

	512,635	1,819,752	1,262,787	(196,465)	3,398,709
CAPITALIZATION:					
Common stockholder s equity	1,859,363	78,542	1,392,642	(1,471,184)	1,859,363
Long-term debt		1,057,252	556,970		1,614,222
	1,859,363	1,135,794	1,949,612	(1,471,184)	3,473,585
NONCURRENT LIABILITIES:					
Accumulated deferred income taxes		25,293	129,095	(32,939)	121,449
Accumulated deferred investment tax credits		38,894	26,857		65,751
Asset retirement obligations		24,272	735,956		760,228
Retirement benefits	10,255	92,772			103,027
Property taxes		21,268	23,165		44,433
Other	26,045	5,780			31,825
	36,300	208,279	915,073	(32,939)	1,126,713
	$ 2,408,298	$ 3,163,825	$ 4,127,472	$ (1,700,588)	$ 7,999,007

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FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(Unaudited)

For the Nine Months Ended September 30, 2007	FES	FGCO	NGC *(In thousands)*	Eliminations	Consolidated
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (17,080)	$ 350,927	$ 146,468	$	$ 480,315
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt		1,328,919		(1,328,919)	
Equity contribution from parent	710,468	700,000	1,325	(701,325)	710,468
Short-term borrowings, net	223,942		13,128	(237,070)	
Redemptions and Repayments-					
Long-term debt		(795,019)	(315,155)		(1,110,174)
Short-term borrowings, net		(1,022,197)		237,070	(785,127)
Common stock	(600,000)				(600,000)
Common stock dividend payments	(67,000)				(67,000)
Net cash provided from (used for) financing activities	267,410	211,703	(300,702)	(2,030,244)	(1,851,833)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10,119)	(332,499)	(140,289)		(482,907)
Proceeds from asset sales		12,990			12,990
Proceeds from sale and leaseback transaction				1,328,919	1,328,919
Sales of investment securities held in trusts			521,535		521,535
Purchases of investment securities held in trusts			(521,535)		(521,535)
Loan repayments from (loans to) associated companies, net	460,023	(242,612)	292,896		510,307
Investment in subsidiary	(701,325)			701,325	
Other	1,091	(509)	1,627		2,209
Net cash provided from (used for) investing activities	(250,330)	(562,630)	154,234	2,030,244	1,371,518
Net change in cash and cash equivalents					
Cash and cash equivalents at beginning of period	2				2
Cash and cash equivalents at end of period	$ 2	$	$	$	$ 2

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FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(Unaudited)

For the Nine Months Ended September 30, 2006	FES	FGCO	NGC *(In thousands)*	Eliminations	Consolidated
NET CASH PROVIDED FROM OPERATING ACTIVITIES	$ 145,390	$ 72,860	$ 239,855	$	$ 458,105
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt		146,704	105,241		251,945
Short-term borrowings, net		66,817			66,817
Redemptions and Repayments-					
Long-term debt		(146,740)	(106,500)		(253,240)
Net cash provided from financing activities		66,781	(1,259)		65,522
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(699)	(131,853)	(294,746)		(427,298)
Proceeds from asset sales		20,437			20,437
Sales of investment securities held in trusts			886,863		886,863
Purchases of investment securities held in trusts			(886,863)		(886,863)
Loans to associated companies	(145,734)		57,442		(88,292)
Other	1,043	(28,225)	(1,292)		(28,474)
Net cash used for investing activities	(145,390)	(139,641)	(238,596)		(523,627)
Net change in cash and cash equivalents					
Cash and cash equivalents at beginning of period	2				2
Cash and cash equivalents at end of period	$ 2	$	$	$	$ 2

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this prospectus to identify us and our affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an affiliated Ohio electric utility
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial and other corporate support services
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, former parent company of several heating, ventilation, air conditioning and energy management companies
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
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, an affiliated Pennsylvania electric utility
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an affiliated Ohio electric utility
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, an affiliated Pennsylvania electric utility
Penn	Pennsylvania Power Company, an affiliated Pennsylvania electric utility
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
TE	The Toledo Edison Company, an affiliated Ohio electric utility
TESBA	Termobarranquilla S.A., Empresa de Servicios Publicos

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The following abbreviations, acronyms and defined terms are used to identify frequently used terms in this prospectus:

2017 Exchange Notes	Up to $250,000,000 in aggregate principal amount of our registered 5.65% Exchange Senior Notes due 2017
2037 Exchange Notes	Up to $300,000,000 in aggregate principal amount of our registered 6.15% Exchange Senior Notes due 2037
2017 Notes	$250,000,000 of our unregistered 5.65% Senior Notes due 2017
2037 Notes	$300,000,000 of our unregistered 6.15% Senior Notes due 2037
AEP	American Electric Power Company, Inc.
AFR	Applicable Federal Rate
ALJ	Administrative Law Judge
APIC	Additional Paid-in Capital
AOCL	Accumulated Other Comprehensive Loss
ARO	Asset Retirement Obligation
BG&E	Baltimore Gas & Electric Company
BGS	Basic Generation Service
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CBP	Competitive Bid Process
CEO	Chief Executive Officer
CMEP	Compliance Monitoring and Enforcement Program
CO_2	Carbon Dioxide
Code	Internal Revenue Code of 1986, as amended from time to time, and any successor statute
COO	Chief Operating Officer
Director s Plan	FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, as it may be amended from time to time
DOJ	United States Department of Justice
DRA	Division of Rate Payer Advocate
DTC	The Depository Trust Company
ECAR	East Central Area Reliability Coordination Agreement
EDCP	FirstEnergy Executive Deferred Compensation Plan, as it may be amended from time to time
EEI Index	Edison Electric Institute s Index of Investor-Owned Electric Utility Companies
EIS	Energy Independence Strategy
EITF	Emerging Issues Task Force
EITF 06-11	EITF 06-11 Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency

EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
Exchange Act	Securities Exchange Act of 1934, as amended
Exchange Notes	2017 Exchange Notes and 2037 Exchange Notes
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 39-1	FIN 39-1, Amendment of FASB Interpretation No. 39
FIN 46R	FIN 46 (revised December 2003), Consolidation of Variable Interest Entities
FIN 47	FIN 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143
FIN 48	FIN 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109
Fitch	Fitch Ratings, Ltd.
FMB	First Mortgage Bonds
FPA	Federal Power Act
FRP	Forked River Power LLC
FSP	FASB Staff Position
FSP FIN 46(R)-6	FASB Staff Position No. FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)
FSP SFAS 115-1 and SFAS 124-1	FASB Staff Position No. 115-1 and SFAS 124-1, The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
HAMBE	Highest Average Monthly Based Earnings
Incentive Plan	FirstEnergy s Executive and Director Incentive Compensation Plan, as it may be amended from time to time
IRS	Internal Revenue Service
ISO	Independent Service Operator
kV	Kilovolt
KWH	Kilowatt-hours
LOC	Letter of Credit
LSE	Load Serving Entity
LTIP	FirstEnergy Long-Term Incentive Program, as it may be amended from time to time
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody s	Moody s Investors Service
MOU	Memorandum of Understanding

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MTC	Market Transition Charge
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOPR	Notice of Proposed Rulemaking
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
OCA	Office of Consumer Advocate
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
Original Notes	2017 Notes and 2037 Notes
Pension Plan	FirstEnergy Pension Plan, as it may be amended from time to time
PICA	Penelec Industrial Consumer Advocate
PJM	PJM Interconnection L.L.C.
PLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RTO	Regional Transmission Organization
RTOR	Regional Through and Out Rates
S&P	Standard & Poor s Ratings Service
Savings Plan	FirstEnergy Savings Plan, as it may be amended from time to time
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
Securities Act	Securities Act of 1933, as amended
SERP	FirstEnergy Supplemental Executive Retirement Plan, as it may be amended from time to time

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SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS 87	SFAS No. 87, Employers Accounting for Pensions
SFAS 101	SFAS No. 101, Accounting for Discontinuation of Application of SFAS 71
SFAS 106	SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions
SFAS 107	SFAS No. 107, Disclosures about Fair Value of Financial Instruments
SFAS 109	SFAS No. 109, Accounting for Income Taxes
SFAS 115	SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities
SFAS 123R	SFAS No. 123R, Share-Based Payment
SFAS 133	SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 142	SFAS No. 142, Goodwill and Other Intangible Assets
SFAS 143	SFAS No. 143, Accounting for Asset Retirement Obligations
SFAS 144	SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS 157	SFAS No. 157, Fair Value Measurements
SFAS 158	SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)
SFAS 159	SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115
SIP	State Implementation Plan(s) under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
Special Severance Agreement	As described under Compensation Discussion and Analysis Elements of Compensation Change in Control.
SRM	Special Reliability Master
STIP	FirstEnergy Short-Term Incentive Program, as it may be amended from time to time
TBC	Transition Bond Charge
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

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Offer To Exchange

$250,000,000 5.65% Exchange Senior Notes due 2017 that have been registered under the Securities Act of 1933 for all outstanding unregistered 5.65% Senior Notes due 2017

$300,000,000 6.15% Exchange Senior Notes due 2037 that have been registered under the Securities Act of 1933 for all outstanding unregistered 6.15% Senior Notes due 2037

Until February 12, 2008, all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters with respect to their unsold allotments or subscriptions.