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All Original Notes that are validly tendered, and not validly withdrawn, will be exchanged.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

	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

	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;

	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

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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

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	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 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.

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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.

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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.

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.

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 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.

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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

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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;

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- 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

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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.

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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 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.

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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

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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

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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

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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.	