PSEG POWER LLC
Form 10-K
February 28, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
100 F. ST N.E.
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

S **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006,
OR
£ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE TRANSITION PERIOD FROM TO .

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
000-49614	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
000-32503	PSEG ENERGY HOLDINGS L.L.C. (A New Jersey Limited Liability Company) 80 Park Plaza T20 Newark, New Jersey 07102-4194 973 430-7000	42-1544079

http://www.pseg.com

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange

5.381% Preferred Trust Securities, $50 liquidation amount per Preferred Trust Security, issued by PSEG Funding Trust I (Registrant) and listed on the New York Stock Exchange.

Trust Originated Preferred Securities (Guaranteed Preferred Beneficial Interest in PSEG s Debentures), $25 par value at 8.75%, issued by PSEG Funding Trust II (Registrant) and listed on the New York Stock Exchange.

Registrant	Title of Each Class	Title of Each Class			Name of Each Exchange On Which Registered
Public Service Electric and Gas Company	**Cumulative Preferred Stock $100 par value Series:**	**First and Refunding Mortgage Bonds:**			
			Series	**Due**	
	4.08%	$9^{1}/_{4}$ %	CC	2021	
	4.18%	$6^{3}/_{4}$ %	VV	2016	New York Stock Exchange
	4.30%	$6^{1}/_{4}$ %	WW	2007	
	5.05%	$6^{3}/_{8}$ %	YY	2023	
	5.28%	8 %		2037	
		5 %		2037	

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Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Class
Public Service Enterprise Group Incorporated	Floating Rate Capital Securities (Guaranteed Preferred Beneficial Interest in PSEG s Debentures), $1,000 par value issued by Enterprise Capital Trust II (Registrant), LIBOR plus 1.22%
	Floating Rate Notes, Series A
Public Service Electric and Gas Company	6.92% Cumulative Preferred Stock $100 par value Medium-Term Notes, Series A Medium-Term Notes, Series B Medium-Term Notes, Series C Medium-Term Notes, Series D
PSEG Power LLC	Limited Liability Company Membership Interest
PSEG Energy Holdings L.L.C.	Limited Liability Company Membership Interest

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

Public Service Enterprise Group Incorporated	Yes S	No £
Public Service Electric and Gas Company	Yes £	No S
PSEG Power LLC	Yes £	No S
PSEG Energy Holdings L.L.C.	Yes £	No S

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes £ No S

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes S No £

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

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
(Check one):

Public Service Enterprise Group Incorporated	Large accelerated filer S	Accelerated filer £	Non-accelerated filer £
Public Service Electric and Gas Company	Large accelerated filer £	Accelerated filer £	Non-accelerated filer S
PSEG Power L.L.C.	Large accelerated filer £	Accelerated filer £	Non-accelerated filer S
PSEG Energy Holdings L.L.C.	Large accelerated filer £	Accelerated filer £	Non-accelerated filer S

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes £ No S

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2006 was $16,424,868,840 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated s sole class of Common Stock, as of the latest practicable date, was as follows:

Class	**Outstanding at January 31, 2007**
Common Stock, without par value	252,771,080

As of January 31, 2007, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and PSEG Energy Holdings L.L.C. are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are filing their respective Annual Reports on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	**Documents Incorporated by Reference**
III	Portions of the definitive Proxy Statement for the 2007 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 5, 2007, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management s beliefs as well as assumptions made by and information currently available to management. When used herein, the words anticipate, intend, estimate, believe, expect, plan, hypothetical, potential, forecast, of such words and similar expressions are intended to identify forward-looking statements. Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G), PSEG Power LLC (Power) and PSEG Energy Holdings L.L.C. (Energy Holdings) undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The following review should not be construed as a complete list of factors that could affect forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements discussed above, factors that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

regulatory issues that significantly impact operations;

ability to attain satisfactory regulatory results;

operating performance or cash flow from investments falling below projected levels;

credit, commodity, interest rate, counterparty and other financial market risks;

liquidity and the ability to access capital and maintain adequate credit ratings;

adverse or unanticipated weather conditions that significantly impact costs and/or operations, including generation;

ability to attract and retain management and other key employees;

changes in the electric industry, including changes to power pools;

changes in energy policies and regulation;

changes in demand;

changes in the number of market participants and the risk profiles of such participants;

availability of power transmission facilities that impact the ability to deliver output to customers;

growth in costs and expenses;

environmental regulations that significantly impact operations;

changes in rates of return on overall debt and equity markets that could adversely impact the value of pension and other postretirement benefits assets and liabilities and the Nuclear Decommissioning Trust Funds;

changes in political conditions;

changes in technology that make generation, transmission and/or distribution assets less competitive;

continued availability of insurance coverage at commercially reasonable rates;

involvement in lawsuits, including liability claims and commercial disputes;

acquisitions, divestitures, mergers, restructurings or strategic initiatives that change PSEG s, PSE&G s, Power s and Energy Holdings strategy or structure;

business combinations among competitors and major customers;

general economic conditions, including inflation or deflation;

changes in tax laws and regulations;

changes to accounting standards or accounting principles generally accepted in the U.S., which may require adjustments to financial statements;

ability to recover investments or service debt as a result of any of the risks or uncertainties mentioned herein;

acts of war or terrorism;

PSEG, PSE&G and Energy Holdings

adverse changes in rate regulation and/or ability to obtain adequate and timely rate relief;

PSEG, Power and Energy Holdings

inability to effectively manage portfolios of electric generation assets, gas supply contracts and electric and gas supply obligations;

inability to meet generation operating performance expectations;

energy transmission constraints or lack thereof;

adverse changes in the market for energy, capacity, natural gas, emissions credits, congestion credits and other commodity prices, especially during significant price movements for natural gas and power;

adverse market developments or changes in market rules, including delays or impediments to implementation of reasonable capacity markets;

surplus of energy capacity and excess supply;

substantial competition in the domestic and worldwide energy markets;

margin posting requirements, especially during significant price movements for natural gas and power;

availability of fuel and timely transportation at reasonable prices;

effects on competitive position of actions involving competitors or major customers;

changes in product or sourcing mix;

delays, cost escalations or unsuccessful construction and development;

PSEG and Power

changes in regulation and safety and security measures at nuclear facilities;

ability to maintain nuclear operating performance at projected levels;

PSEG and Energy Holdings

changes in foreign currency exchange rates;

deterioration in the credit of lessees and their ability to adequately service lease rentals;

ability to realize tax benefits;

- changes in political regimes in foreign countries; and
- international developments negatively impacting business.

Consequently, all of the forward-looking statements made in this report are qualified by these cautionary statements and PSEG, PSE&G, Power and Energy Holdings cannot assure you that the results or developments anticipated by management will be realized, or even if realized, will have the expected consequences to, or effects on, PSEG, PSE&G, Power and Energy Holdings or their respective business prospects, financial condition or results of operations. Undue reliance should not be placed on these forward-looking statements in making any investment decision. Each of PSEG, PSE&G, Power and Energy Holdings expressly disclaims any obligation or undertaking to release publicly any updates or revisions to these forward-looking statements to reflect events or circumstances that occur or arise or are anticipated to occur or arise after the date hereof. In making any investment decision regarding PSEG s, PSE&G s, Power s and Energy Holdings securities, PSEG, PSE&G, Power and Energy Holdings are not making, and you should not infer, any representation about the likely existence of any particular future set of facts or circumstances. The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

WHERE TO FIND MORE INFORMATION

Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G), PSEG Power LLC (Power) and PSEG Energy Holdings L.L.C. (Energy Holdings) file annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may read and copy any document that PSEG, PSE&G, Power and Energy Holdings file at the Public Reference Room of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain PSEG s, PSE&G s, Power s and Energy Holdings filings on the Internet at the SEC s website at www.sec.gov or at PSEG s website, www.pseg.com. PSEG s Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about PSEG at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

PART I

This combined Annual Report on Form 10-K is separately filed by PSEG, PSE&G, Power and Energy Holdings. Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G, Power and Energy Holdings each makes representations only as to itself and its subsidiaries and makes no other representations whatsoever as to any other company.

ITEM 1. BUSINESS

GENERAL

PSEG, PSE&G, Power and Energy Holdings

PSEG was incorporated under the laws of the State of New Jersey in 1985 and has its principal executive offices located at 80 Park Plaza, Newark, New Jersey 07102. PSEG has four principal direct wholly owned subsidiaries: PSE&G, Power, Energy Holdings and PSEG Services Corporation (Services). The following organization chart shows PSEG and its principal subsidiaries, as well as the principal operating subsidiaries of Power: PSEG Fossil LLC (Fossil), PSEG Nuclear LLC (Nuclear) and PSEG Energy Resources & Trade LLC (ER&T); and of Energy Holdings: PSEG Global L.L.C. (Global) and PSEG Resources L.L.C. (Resources):

PSEG is an energy company with a diversified business mix. PSEG s operations are primarily in the Northeastern and Mid Atlantic United States (U.S.) and in other select markets. As the competitive portion of PSEG s business has grown, the resulting financial risks and rewards have become greater, causing financial requirements to change and increasing the volatility of earnings and cash flows.

For additional information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) Overview of 2006 and Future Outlook.

Termination of Merger Agreement

On December 20, 2004, PSEG entered into an Agreement and Plan of Merger (Merger Agreement) with Exelon Corporation (Exelon) providing for a merger of PSEG with and into Exelon (Merger). On September 14, 2006, PSEG received from Exelon a formal notice terminating the Merger under the provisions of the Merger Agreement.

PSE&G

PSE&G is a New Jersey corporation, incorporated in 1924, and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSE&G is an operating public utility company engaged principally in the transmission and distribution of electric energy and gas in New Jersey. In addition, PSE&G owns PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which are bankruptcy-remote entities that purchased the irrevocable right to receive certain non-bypassable charges per Kilowatt-hour (kWh) of energy delivered to PSE&G customers and issued transition bonds secured by such property.

PSE&G provides electric and gas service in areas of New Jersey in which approximately 5.5 million people, about 70% of the state s population, reside. PSE&G s electric and gas service area is a corridor of approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the city of Camden in the southwest. The greater portion of this area is served with both electricity and gas, but some parts are served with electricity only and other parts with gas only. This heavily populated, commercialized and industrialized territory encompasses most of New Jersey s largest municipalities, including its six largest cities Newark, Jersey City, Paterson, Elizabeth, Trenton and Camden in addition to approximately 300 suburban and rural communities. This service territory contains a diversified mix of commerce and industry, including major facilities of many nationally prominent corporations. PSE&G s load requirements are split among residential, commercial and industrial customers, described below under customers. PSE&G believes that it has all the non-exclusive franchise rights (including consents) necessary for its electric and gas distribution operations in the territory it serves.

Energy Supply

PSE&G distributes electric energy and gas to end-use customers within its designated service territory. All electric and gas customers in New Jersey have the ability to choose an electric energy and/or gas supplier. Pursuant to the New Jersey Board of Public Utilities (BPU) requirements, PSE&G serves as the supplier of last resort for electric and gas customers within its service territory. PSE&G earns no margin on the commodity portion of its electric and gas sales.

As shown in the table below, PSE&G continues to provide the electric energy and gas supply for the majority of the customers in its service territory for the year ended December 31, 2006.

	GWH	%	Million Therms	%
PSE&G	34,340	79	1,975	62
Third Party Suppliers	9,323	21	1,194	38
Total Delivered	43,663	100	3,169	100

New Jersey s Electric Distribution Companies (EDCs), including PSE&G, provide two types of Basic Generation Service (BGS). BGS-Fixed Price (FP) provides supply for smaller commercial and residential customers at seasonally-adjusted fixed prices and BGS-Commercial and Industrial Energy Price (CIEP) provides supply for larger customers at hourly PJM Interconnection, L.L.C. (PJM) real- time market prices. BGS prices are determined through annual auctions conducted before the BPU.

PSE&G has a full requirements contract with Power to meet the Basic Gas Supply Service (BGSS) requirements of PSE&G s gas customers. The contract term extends to March 31, 2012, and year-to-year thereafter. Power charges PSE&G for gas commodity costs which PSE&G recovers from its customers.

Any difference between the BGS and BGSS costs and revenues received from PSE&G s residential customers are deferred and collected or refunded through adjustments in future rates.

Distribution Rates

PSE&G earns margins through the transmission and distribution of electricity and gas. PSE&G s revenues for these services are based upon tariffs approved by the BPU and FERC. Approximately 98% of PSE&G s 2006 revenues were covered by BPU tariffs. The demand for electric energy and gas by PSE&G s customers is affected by customer conservation, economic conditions, weather and other factors not within PSE&G s control.

On November 9, 2006 the BPU approved separate settlements providing for increases in PSE&G s electric and gas base rates. The settlements include a restriction against any further base rate changes becoming effective before November 15, 2009. In addition, PSE&G must file a joint electric and gas petition for any future base rate increases. For additional information on these settlements, see Regulatory Issues State Regulation.

Market Price Environment

Over the past few years, there has been a significant volatility in commodity prices, including fuel, emission allowances and electricity. Such volatility can have a considerable impact on PSE&G since a rising commodity price environment results in higher delivered electric and gas rates for end-use customers, and may result in decreased demand by end users of both electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs may be deferred under PSEG s regulated rate structure. For additional information see Item 7. MD&A.

Competitive Environment

The electric and gas transmission and distribution business has minimal risks from competitors. PSE&G s transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since PSE&G earns its return by providing transmission and distribution service, not by supplying the commodity.

Customers

As of December 31, 2006, PSE&G provided service to approximately 2.1 million electric customers and approximately 1.7 million gas customers, detailed below. In addition to its transmission and distribution business, PSE&G also offers appliance services and repairs to customers throughout its service territory.

	% of Sales	
	Electric	**Gas**
Customer Type		
Commercial	56 %	36 %
Residential	31 %	60 %
Industrial	13 %	4 %
Total	100 %	100 %

Employee Relations

As of December 31, 2006, PSE&G had 6,154 employees. PSE&G has six-year collective bargaining agreements, which were ratified in 2005, with four unions representing 4,955 employees. PSE&G believes that it maintains satisfactory relationships with its employees.

Power

Power is a Delaware limited liability company, formed in 1999, and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. Power is a multi-regional, wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management functions through three principal direct wholly owned subsidiaries: Nuclear, Fossil and ER&T.

As of December 31, 2006, Power s generation portfolio consisted of approximately 14,639 MW of installed capacity, which is primarily located in the Northeast and Mid Atlantic regions of the U.S. where some of the nation s largest and most developed energy markets are located. For additional information, see Item 2. Properties.

As a merchant generator, Power s profit is derived from selling under contract or on the spot market a range of diverse products such as energy, capacity, emissions credits, congestion credits and a series of energy-related products used to optimize the operation of the energy grid, known as ancillary services. Power s revenues also include gas supply sales under the BGSS contract with PSE&G.

Nuclear

Nuclear has an ownership interest in five nuclear generating units: the Salem Nuclear Generating Station, Units 1 and 2 (Salem 1 and 2), each owned 57.41% by Nuclear and 42.59% by Exelon Generation; the Hope Creek Nuclear Generating Station (Hope Creek), which is owned 100% by Nuclear; and, the Peach Bottom Atomic Power Station Units 2 and 3 (Peach Bottom 2 and 3), each of which is operated by Exelon Generation and owned 50% by Nuclear and 50% by Exelon Generation. For additional information, see Item 2. Properties Power.

Nuclear Operations

In January 2005, Nuclear entered into an Operating Service Contract (OSC) with Exelon Generation relating to the operation of the Hope Creek and Salem nuclear generating stations. The OSC requires Exelon Generation to provide key personnel to oversee daily plant operations at the Hope Creek and Salem nuclear generating stations and to implement a management model that Exelon has used to manage its own nuclear facilities. Nuclear continues as the license holder with exclusive legal authority to operate and maintain the Salem and Hope Creek plants, retains responsibility for management oversight and has full authority with respect to the marketing of its share of the output from the facilities. In October 2006, Nuclear informed Exelon Generation that it was electing to continue the OSC for up to two years beyond the initial January 2007 period.

In December 2006, Power announced its plans to resume direct management of the Salem and Hope Creek nuclear generating stations before the expiration of the OSC. As part of this plan, on January 1, 2007, the senior management team at Salem and Hope Creek, which consisted of three senior executives from Exelon Generation, became employees of Power.

During 2006, over half of Power s generating output was from its nuclear generating stations. Nuclear unit capacity factors for 2006 were as follows:

Unit	**Capacity Factor***
Salem Unit 1	100.7 %
Salem Unit 2	93.6 %
Hope Creek	92.6 %
Peach Bottom Unit 2	93.3 %
Peach Bottom Unit 3	101.8 %
Total Power Ownership	95.9 %

* Maximum Dependable Capacity (MDC) net.

For additional information on recent operational issues, see Regulatory Issues Nuclear Regulatory Commission (NRC).

Nuclear Fuel

Nuclear has several long-term purchase contracts for the supply of nuclear fuel for the Salem and Hope Creek Nuclear Generating Stations which include:

- purchase of uranium (concentrates and uranium hexafluoride);
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride; and
- fabrication of nuclear fuel assemblies.

The nuclear fuel markets are competitive and although prices for uranium, conversion and enrichment are increasing, Nuclear does not anticipate any significant problems in meeting its future requirements.

Nuclear has been advised by Exelon Generation that it has similar purchase contracts to satisfy the fuel requirements for Peach Bottom. For additional information, see Item 7. MD&A Overview of 2006 and Future Outlook Power and Note 12. Commitments and Contingent Liabilities of the Notes.

Fossil

Fossil has an ownership interest in 17 generating stations, primarily in the Northeast and Mid Atlantic U.S., including the Bethlehem Energy Center in New York and the Linden station in New Jersey, which were completed and placed in service in 2005 and 2006, respectively. Power s facility in Indiana, the Lawrenceburg Energy Center, is currently under an agreement to be sold. For additional information, see Item 2. Properties Power.

Fossil uses coal, natural gas and oil for electric generation. These fuels are purchased through various contracts and in the spot market and represent a significant portion of Power s working capital requirements. In order to minimize emissions levels, the Bridgeport generating facility uses a specific type of coal, which is obtained from Indonesia through a fixed-price supply contract that runs through 2008. If the supply of coal from Indonesia or equivalent coal from other sources was not available for the Connecticut facilities, additional material capital expenditures could be required to modify the existing plants to enable their continued operation. In addition, the Hudson facility, under a consent decree with the New Jersey Department of Environmental Protection (NJDEP) and the U.S. Environmental Protection Agency (EPA), will also utilize this type of coal. Power believes it has access to sufficient fuel supply, including transportation, for its facilities over the next several years. For additional information, see Item 7. MD&A Overview of 2006 and Future Outlook Power and Note 12. Commitments and Contingent Liabilities of the Notes.

ER&T

ER&T purchases the capacity and energy produced by each of the generation subsidiaries of Power. In conjunction with these purchases, ER&T uses commodity and financial instruments designed to cover estimated commitments for BGS and other bilateral contract agreements. ER&T also markets electricity, capacity, ancillary services and natural gas products on a wholesale basis. ER&T is a fully integrated wholesale energy marketing and trading organization that is active in the long-term and spot wholesale energy and energy-related markets.

Electric Supply

Power s generation capacity is comprised of a diverse mix of fuels of approximately 47% gas, 26% nuclear, 18% coal, 8% oil and 1% pumped storage. Power s fuel diversity serves to mitigate risks associated with fuel price volatility and market demand cycles.

The following table indicates proportionate MWh output of Power s generating stations by fuel type, based on actual 2006 output of approximately 54,000 MWhs, and its estimated 53,000 MWh output by fuel type for 2007.

Generation by Fuel Type	Actual 2006	Estimated 2007(A)
Nuclear:		
New Jersey facilities	37 %	37 %

Pennsylvania facilities	18 %	18 %
Fossil:		
Coal:		
New Jersey facilities	11 %	11 %
Pennsylvania facilities	11 %	11 %
Connecticut facilities	5 %	4 %
Oil and Natural Gas:		
New Jersey facilities	12 %	14 %
New York facilities	4 %	3 %
Connecticut facilities	1 %	1 %
Pumped Storage	1 %	1 %
Total	100 %	100 %

(A) No assurances can be given that actual 2007 output by source will match estimates.

For a discussion of Power s management and hedging strategy relating to its energy sales supply and fuel needs, see Market Price Environment and Item 7A. MD&A Overview of 2006 and Future Outlook Power.

Gas Supply

As described above, Power sells gas to PSE&G under the BGSS contract. Additionally, based upon availability, Power sells gas to others. About 41% of PSE&G s peak daily gas requirements are provided through firm transportation, which is available every day of the year. The remainder comes from field storage, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery and landfill gas. Power purchases gas for its gas operations directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipeline suppliers.

Power has approximately 1 billion cubic-feet-per-day of firm transportation capacity under contract to meet the primary needs of PSE&G s gas consumers and the needs of its own generation fleet. In addition, Power supplements that supply with a total storage capacity of 78 billion cubic feet that provides a maximum of approximately 1 billion cubic feet-per-day of gas during the winter season.

Power expects to be able to meet the energy-related demands of its firm natural gas customers. However, the ability to maintain an adequate supply could be affected by several factors not within Power s control, including curtailments of natural gas by its suppliers, severe weather and the availability of feedstocks for the production of supplements to its natural gas supply. In addition, supply of all types of gas is affected by the nationwide availability of all sources of fuel for energy production.

Market Price Environment

System operators in the electric markets in which Power participates will generally dispatch the lowest cost units in the system first, with higher cost units dispatched as demand increases. As such, nuclear units, with their low variable cost of operation, will generally be dispatched whenever they are available. Coal units generally follow next in the merit order of dispatch and gas and oil units generally follow to meet the total amount of demand. The price that all dispatched units receive is set by the last, or marginal unit that is dispatched.

This method of determining supply and pricing creates an environment where natural gas prices often have a major impact on the price that generators will receive for their output, especially in periods of relatively strong demand. As such, significant changes in the price of natural gas will often translate into significant changes in the price of electricity.

As a merchant generator, Power s profit is derived from selling under contract or on the spot market a range of diverse products such as energy, capacity, emissions credits, congestion credits and a series of energy-related products that the system operator uses to optimize the operation of the energy grid, known as ancillary services. Accordingly, commodity prices, such as electricity, gas, coal and emissions, as well as the availability of Power s diverse fleet of generation units to produce these products, when necessary, have a considerable effect on Power s profitability. There is significant volatility in commodity markets, including electricity, fuel and emission allowances. For example, the spot price of electricity at the quoted PJM West market has increased from an average of about $25 per MWh for 2002 to an average of about $60 per MWh in 2005 and then decreased to an average of about $50 per MWh in 2006. Similarly, the price of natural gas at the Henry Hub terminal has increased from an average of about $3 per one million British Thermal Units (MMBtu) in 2002 to about $9 per MMBtu in 2005 and then decreased to an average of about $7 per MMBtu in 2006. The prices at which transactions are entered into for future delivery of these products, as evidenced through the market for forward contracts at points such as PJM West, have escalated as well. The historical spot prices and forward prices as of year-end 2006 are reflected in the graphs below.

In the electricity markets where Power participates, the pricing of electricity can vary by location. For example, prices may be higher in congested areas due to transmission constraints during peak demand periods reflecting the bid prices of the higher cost units that are dispatched to supply demand. This typically occurs in the eastern portion of PJM, where many of Power s plants are located. At various times, depending upon its production and its obligations, these price differentials can serve to increase or decrease Power s profitability.

While the prices reflected in the tables above do not necessarily represent prices at which Power has contracted, they are representative of market prices at relatively liquid hubs, with nearer term forward pricing generally resulting from more liquid markets than pricing for later years. While they provide some perspective on past and future prices and recent prices are considerably higher than in prior years, the forward prices are highly volatile, and there is no assurance that such prices will remain in effect nor that Power will be able to contract its output at these forward prices.

Power is also provided with payments from the various markets for the capability to provide electricity, known as a capacity payments, which are reflective of the value to the grid for having the assurance of sufficient generating capacity to meet system reliability and energy requirements, and to encourage the future investment in adequate sources of new generation to meet system demand. While there is generally sufficient capacity in the markets in which Power operates, there are certain areas in these markets where there are constraints in the transmission system, causing concerns for reliability and a more acute need for capacity. Some generators, including Power, announced the retirement of certain older generating facilities in these constrained areas due to insufficient revenues to support their continued operation. In separate instances, both PJM and the New England Power Pool (NEPOOL) responded with Reliability-Must-Run (RMR) contracts for these units to enable their continued availability that provide their owners with fixed payments which, while not necessarily reflective of the full value of those units contribution to reliability (e.g. they are cost-based), are nonetheless significant. Such payment structure by its nature acknowledges that these units provide a reliability service that is not compensated in the existing markets. It also suggests that fixed periodic payments, as would be provided in a capacity market, are an appropriate form of compensation for such units for this service. Power receives RMR payments in both PJM and NEPOOL.

In addition, FERC issued certain orders in 2006 related to market design that have changed the nature of capacity payments in the New England Power Pool (NEPOOL) and is scheduled to change the nature of payments in PJM. In PJM, a new capacity-pricing regime known as the Reliability Pricing Model (RPM) will provide generators with differentiated capacity payments based upon the location of their respective facilities. Similarly, the Forward Capacity Market (FCM) settlement in NEPOOL provides for locational capacity payments. Both market designs are based in part on the premise that a more structured, forward-looking, transparent pricing scheme will give prospective investors in new generating facilities more clarity on the future value of capacity, sending a pricing signal to encourage expansion of capacity for future market demands. FERC has approved the market changes in each of these markets, with the anticipated start date for RPM set for June 1, 2007 and FCM transition period having begun on December 1, 2006. Power believes that the majority of its generating capacity may experience changes in value from aspects of these market designs. While Power believes it may derive considerable additional revenue from these changes, it is difficult to predict the ultimate outcome of these changes.

For additional information on Power s collection of RMR payments in PJM and NEPOOL and the RPM and FCM proposals, see Regulatory Issues Federal Regulation.

Competitive Environment

Power s competitors include merchant generators with or without trading capabilities, including banks, funds and other financial entities, utilities that have generating capability or have formed generation and/or trading affiliates, aggregators, wholesale power marketers and developers of transmission and Demand Side Management (DSM) projects and combinations thereof. These participants compete with Power and one another buying and selling in wholesale power pools, entering into bilateral contracts and/or selling to aggregated retail customers.

Power s businesses are also under competitive pressure due to technological advances in the power industry and increased efficiency in certain energy markets. For example, it is possible that advances in technology, such as distributed generation, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production.

There is also a risk to Power if states should decide to turn away from competition and allow regulated utilities to continue to own or reacquire and operate generating stations in a regulated and potentially uneconomical manner, or to encourage rate-based generation for the construction of new base-load units. This has already occurred in certain states. The lack of consistent rules in energy markets can negatively impact the competitiveness of Power s plants. Also, regional inconsistencies in environmental regulations, particularly those related to emissions, have put some of Power s plants which are located in the Northeast, where rules are more stringent, at an economic disadvantage compared to its competitors in certain Midwest states.

Also, environmental issues such as air pollution controls may have a competitive impact on Power to the extent its plants are more expensive to maintain in compliance, thus affecting its ability to be a lower cost provider compared to competitors without such restrictions.

In addition, as discussed in the Regulatory Issues section herein specifically, in the discussion concerning (i) Transmission Rates and Cost Allocation and (ii) Transmission Infrastructure current rules being developed at FERC, at DOE and at PJM with respect to the construction of transmission and the allocation of costs for such construction may have the effect of altering the level playing field between transmission options and generation options, which could have a competitive impact upon PSEG and Power.

Customers

As EWGs, Power s subsidiaries do not directly serve retail customers. Power uses its generation facilities primarily for the production of electricity for sale at the wholesale level. Power s customers consist mainly of wholesale buyers, primarily within PJM, but also in New York and Connecticut. Power is at times a direct or indirect supplier of New Jersey s EDCs, including PSE&G, depending on the positions it takes in the New Jersey BGS auction. In prior years, Power had also been a bidder in the CIEP auction, which serves large industrial and commercial customers at hourly PJM real-time market prices for a term of 12 months. Power s three-year contract with a Connecticut utility ended on December 31, 2006. These contracts are full requirements contracts, where Power is responsible to serve a percentage of the full supply needs of the customer class being served, including energy, capacity, congestion and ancillary services. In addition, Power has four-year contracts with two Pennsylvania utilities expiring in 2008 and is considering pursuing similar opportunities in other states.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G s gas customers. The contract term was originally through March 31, 2007, and year-to-year thereafter. In the settlement of the 2005/06 BGSS proceeding the Parties agreed to an amendment to the contract that changed the contract term to March 31, 2012, and year-to-year thereafter. Power charges PSE&G for gas commodity costs which PSE&G recovers from its customers. Any difference between the residential gas cost charged by Power under the BGSS contract and revenues received from PSE&G s residential customers are deferred and collected or refunded through adjustments in future rates.

For the year ended December 31, 2006, approximately 46% of Power s revenue was comprised of billings to PSE&G for BGS and BGSS. See Note 21. Related-Party Transactions of the Notes for additional information.

Employee Relations

As of December 31, 2006, Power had 2,538 employees, of which 1,414 employees (705 employees for Fossil and 708 employees for Nuclear) are represented by three union groups under six-year collective bargaining agreements, which were ratified in February, July and August 2005, respectively. Power believes that it maintains satisfactory relationships with its employees.

Energy Holdings

Energy Holdings is a New Jersey limited liability company and is the successor to PSEG Energy Holdings Inc., which was incorporated in 1989. Energy Holdings principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. Energy Holdings has two principal direct wholly owned subsidiaries, which are also its segments: Global and Resources.

Energy Holdings pursued investment opportunities in the domestic and international energy markets, with Global focused on the operating segments of the electric industries and Resources primarily made financial investments in these industries.

Global

Global owns investments in power producers and distributors that own and operate electric generation and distribution facilities in selected domestic and international markets. See Item 2. Properties Energy Holdings for discussion of individual investments, including significant power purchase agreements (PPAs), fuel supply agreements, financing structures and other matters.

Global s assets include consolidated projects and those accounted for under the equity method. As of December 31, 2006, Global s share of project MW and number of customers by region are as follows:

	As of December 31, 2006			
	Total Capital Invested (1)	Assets	MW	Number of Customers
		(Millions)		

Chile and Peru Distribution and Generation	$	1,245	$	1,864	303	1,974,000
U.S. Generation		508		911	2,396	N/A
Other		153		343	172	N/A
Total	$	1,906	$	3,118	2,871	1,974,000

(1) Total Capital Invested represents Global s equity invested in the projects, excluding currency translation adjustments.

Energy Holdings has reduced its international risk by opportunistically monetizing investments at Global that no longer had a strategic fit. During the past three years, Global has received proceeds of over $1 billion from sales of investments in China, Brazil, Poland, India, Africa and the Middle East. The decrease in Global s portfolio size due to the above sales was partially offset by strong earnings from its Texas generation facilities and its electric distribution companies in Chile and Peru. As a result, Global s current portfolio is primarily comprised of investments in Chile, Peru and the United States. Global also has modest sized investments in Italy, India and Venezuela totaling about 8% of Global s total investment balance.

As a result of these sales, approximately 50% of Global s future earnings is expected to be derived from its domestic generation business, of which, over half are from its 2,000 MW gas-fired combined cycle merchant generation business in Texas, with the balance from its 12 fully-contracted generating facilities in which Global s ownership interests equate to nearly 400 MW. The other 50% of Global s earnings is expected to be essentially from three electric distribution businesses in Chile and Peru and a 183 MW hydro generation facility in Peru. The regulatory environments in both Chile and Peru have been generally constructive since Global acquired these investments. Rate cases are held every four years (with the next rate case beginning in 2008) and the rate calculation methodologies are designed to achieve a reasonable return on the net replacement value of each system. See Regulation for additional information on the regulatory process in Chile and Peru. Chile also maintains an investment grade rating and Peru s rating, although non-investment grade, has improved.

Energy Holdings continues to review Global s portfolio, with a focus on its international investments. As part of this review, Energy Holdings considers the returns of its remaining investments against alternative investments across the PSEG companies, while considering the strategic fit and relative risks of these businesses.

Market Price Environment

Global s projects in California, Hawaii and New Hampshire are fully contracted under long-term PPAs with the public utilities or power procurers in those areas. Therefore, Global does not have price risk with respect to the output of such assets, and generally, with respect to such assets, has limited risk with respect to fuel prices. Global s risks related to these projects are primarily operational in nature and have historically been minimal.

Global s generation business in Texas (Texas Independent Energy. L. P. (TIE)) is a merchant generation business with higher risks. TIE seeks to enter into a mix of contracts to sell its output approximately 20% of its output is sold under a five-year contract, which expires in 2010, and another 10% to 20% is sold forward under one-year on-peak calendar or seasonal contracts and the balance is sold during the year. As a result, TIE s business is subject to substantial volatility in earnings and cash flows as power prices fluctuate. Although Global s business in Texas has performed very well as high natural gas prices and the resulting high energy prices led to strong margins in 2005 and 2006, there can be no assurances that such pricing in the market will continue at these levels.

Competitive Environment

Although TIE s generating stations operate very efficiently relative to other gas-fired generating plants, new technology could make TIE s plants less economical in the future. Also, several competitors have announced plans to build a substantial amount of capacity in the Electric Reliability Council of Texas (ERCOT) market. Although it is not clear if this capacity will be built or, if so, what the economic impact would be, such additions could impact market prices and TIE s competitiveness. Also, as ERCOT transitions to nodal pricing from zonal pricing the competitiveness of TIE s generating plants could be impacted. As TIE represents a substantial portion of Energy Holdings and Global s business, volatility in that portion of the business will impact Global s and Energy Holdings overall portfolio results.

Of the remaining portion of Global s business, the majority of its earnings are generated by two major rate-regulated distribution businesses in Chile and one in Peru. Although these entities are not granted exclusive franchises, there is minimal competition for distribution companies. See Regulatory Issues International Regulation for a discussion of the ratemaking process in Chile and Peru. Global also owns a hydro generation facility in Peru. Although new generation capacity is being built in Peru, there are not many opportunities for hydro expansion, mitigating competition with Global s hydro generation investment.

Customers

Global has ownership interests in three distribution companies in South America which serve approximately two million customers. Global also has ownership interests in electric generation facilities which sell energy, capacity and ancillary services to numerous customers through PPAs, as well as into the wholesale market. For additional information, see Item 2. Properties Energy Holdings.

Resources

Resources has investments in energy-related financial transactions and manages a diversified portfolio of assets, including leveraged leases, operating leases, leveraged buyout funds, limited partnerships and marketable securities. Established in 1985, Resources has a portfolio of approximately 45 separate investments. Resources does not anticipate making significant additional investments in the near term.

Resources also owns and manages a Demand Side Management (DSM) business. DSM revenues are earned principally from monthly payments received from utilities, which represent shared electricity savings from the installation of the energy efficient equipment.

The major components of Resources investment portfolio as a percent of its total assets as of December 31, 2006 were:

	As of December 31, 2006	
	Amount (Millions)	**% of Resources Total Assets**
Leveraged Leases		
Energy-Related		
Foreign	$ 1,499	51 %
Domestic	1,041	35 %
Real Estate Domestic	182	6 %
Commuter Railcars Foreign	88	3 %
Total Leveraged Leases	2,810	95 %
Owned Property (real estate and aircraft)	124	4 %
Limited Partnerships, Other Investments & Current and Other Assets	35	1 %
Total Resources Assets	$ 2,969	100 %

As of December 31, 2006, no single investment represented more than 10% of Resources total assets.

Leveraged Lease Investments

Resources maintains a portfolio that is designed to provide a fixed rate of return. Income on leveraged leases is recognized by a method which produces a constant rate of return on the outstanding investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded as Operating Revenues as these events occur in the ordinary course of business of managing the investment portfolio.

In a leveraged lease, the lessor acquires an asset by investing equity representing approximately 15% to 20% of the cost of the asset and incurring non-recourse lease debt for the balance. The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. In addition, the lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. The ability of Resources to realize these tax benefits is dependent on operating gains generated by its affiliates and allocated pursuant to PSEG s consolidated tax sharing agreement. The Internal Revenue Service (IRS) has recently disallowed certain tax deductions claimed by Resources for certain of these leases. See Note 12. Commitments and Contingent Liabilities of the Notes for further discussion. Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under generally accepted accounting principles in the U.S. (GAAP), the lease investment is recorded on a net basis and income is recognized as a constant return on the net unrecovered investment.

Resources has evaluated the lease investments it has made against specific risk factors. The assumed residual-value risk, if any, is analyzed and verified by third parties at the time an investment is made. Credit risk is assessed and, in some cases, mitigated or eliminated through various structuring techniques, such as defeasance mechanisms and letters of credit. As of December 31, 2006, the weighted average credit rating of the lessees in the portfolio was A /A3. Resources has not taken currency risk in its cross-border lease investments. Transactions have been structured with rental payments denominated and payable in U.S. dollars. Resources, as a passive lessor or investor, has not taken operating risk with respect to the assets it owns, so leveraged leases have been structured with the lessee having an absolute obligation to make rental payments whether or not the related assets operate. The assets subject to lease are an integral element in Resources overall security and collateral position. If the value of such assets were to be impaired, the rate of return on a particular transaction could be affected. The operating characteristics and the business environment in which the assets operate are, therefore, important and must be understood and periodically evaluated. For this reason, Resources will retain, as necessary, experts to conduct appraisals on the assets it owns and leases.

On December 28, 2005, Resources sold its interest in the Seminole Generation Station Unit 2 in Palatka, Florida. For additional information relating to this disposition, see Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

Resources ten largest lease investments as of December 31, 2006 were as follows:

Investment	Description	Recorded Investment Balances as of December 31, 2006	% of Resources Total Assets
		(Millions)	
Reliant Energy MidAtlantic Power Holdings, LLC	Three generating stations (Keystone, Conemaugh and Shawville)	$ 284	10 %
Dynegy Holdings Inc	Two electric generating stations (Danskammer and Roseton)	239	8 %
Midwest Generation (Guaranteed by Edison Mission Energy)	Two electric generating stations (Powerton and Joliet)	206	7 %
ENECO	Gas distribution network (Netherlands)	168	6 %
ESG	Electric distribution system (Austria)	145	5 %
EZH		133	4 %

	Electric generating station (Netherlands)		
Merrill Creek	Merrill Creek Reservoir Project	130	4 %
Grand Gulf	Nuclear generating station (U.S.)	121	4 %
Nuon	Gas distribution network (Netherlands)	111	4 %
EDON	Gas distribution network (Netherlands)	105	3 %
		$ 1,642	55 %

For additional information on leases, including credit, tax and accounting risk related to certain lessees, see Item 7. MD&A Results of Operations Energy Holdings, Item 7A. Qualitative and Quantitative Disclosures About Market Risk Credit Risk Energy Holdings and Note 12. Commitments and Contingent Liabilities of the Notes.

As of December 31, 2006, Resources has a remaining gross investment in three leased aircraft of approximately $41 million. On September 14, 2005, Delta Airlines (Delta) and Northwest Airlines (Northwest), the lessees for Resources four remaining aircraft at that time, filed for Chapter 11 bankruptcy protection. This had no material effect on Energy Holdings as it continues to believe that it will be able to recover the recorded amount of its investments in these aircraft as of December 31, 2006, although no assurances can be given. In 2004 and 2005, Resources successfully restructured the leases and converted the Delta and Northwest leases from leveraged leases to operating leases. The Delta aircraft was sold in January 2006 generating a small gain for Resources.

Other Subsidiaries

Enterprise Group Development Corporation (EGDC), a commercial real estate property management business, is conducting a controlled exit from its real estate business. Total assets of EGDC as of December 31, 2006 and 2005 were $70 million and $71 million, respectively, less non-recourse debt of $19 million and $21 million, respectively less minority interest of $6 million for each year, for a net investment of approximately $45 million and $44 million, respectively. These investments are composed of three properties in New Jersey, Maryland and Virginia and an 80% partnership interest in buildings and land in New Jersey.

Employee Relations

As of December 31, 2006, Energy Holdings had 53 direct employees. In addition, Energy Holdings subsidiaries had a total of 1,091 employees, of which 692 were represented by unions under collective bargaining agreements expiring between June 2007 and January 2010. Energy Holdings believes that it maintains satisfactory relationships with its employees.

Services

Services is a New Jersey corporation with its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. Services provides management and administrative and general services to PSEG and its subsidiaries. These include accounting, treasury, financial risk management, law, tax, communications, planning, development, human resources, corporate secretarial, information technology, investor relations, stockholder services, real estate, insurance, library, records and information services, security and certain other services. Services charges PSEG and its subsidiaries for the cost of work performed and services provided pursuant to the terms and conditions of intercompany service agreements. As of December 31, 2006, Services had 932 employees, including 100 employees represented by a union group under a six-year collective bargaining agreement that was ratified in February 2005. Services believes that it maintains satisfactory relationships with its employees.

REGULATORY ISSUES

Federal Regulation

Public Utility Holding Company Act (PUHCA)

PSEG, PSE&G, Power and Energy Holdings

The Energy Policy Act (EP Act), which became law on August 8, 2005, repealed PUHCA as of February 8, 2006 and established PUHCA 2005, which grants to FERC books and records oversight of public utility holding companies. PSEG had historically claimed an exemption from regulation by the SEC as a registered holding company under PUHCA. As part of that exemption, Fossil, Nuclear, certain subsidiaries of Fossil and certain subsidiaries of Energy Holdings with domestic operations obtained EWG or Qualifying Facility (QF) status (the latter designation obtained under the Public Utility Regulatory Policies Act of 1978 (PURPA)), while most of Energy Holdings foreign investments obtained Foreign Utility Company (FUCO) status. Notwithstanding the repeal of PUHCA, these companies have retained their designations as EWGs, FUCOs or QFs, since such designation affords certain protections under FERC s PUHCA 2005. Specifically, companies subject to the provisions of PUHCA 2005 must provide state regulators access to their books and records. PSEG, PSE&G, Power and Energy Holdings do not expect PUHCA 2005 to materially affect their respective businesses, prospects or properties, and in October 2006, PSEG obtained from FERC a waiver of

PUHCA 2005 s accounting, record retention and reporting requirements. For additional information on the impact of PUHCA repeal, see State Regulation.

Environmental

PSEG, PSE&G, Power and Energy Holdings

PSEG and its subsidiaries are subject to the rules and regulations relating to environmental issues promulgated by the EPA, the U.S. Department of Energy (DOE) and other regulators. For information on environmental regulation, see Environmental Matters.

FERC

PSEG, PSE&G, Power and Energy Holdings

FERC is an independent federal agency that regulates the transmission of electric energy and sale of electric energy at wholesale in interstate commerce pursuant to the Federal Power Act (FPA). FERC also regulates the interstate transportation of, as well as certain wholesale sales of, natural gas pursuant to the Natural Gas Act. FERC s oversight includes: merger review, compliance, including Standards of Conduct issues, transmission rates and terms and conditions of service, and market power, market design and capacity design and rates. Several PSEG subsidiaries, including PSE&G, Fossil, Nuclear, and ER&T, as well as certain subsidiaries of Fossil and certain domestic subsidiaries of Energy Holdings are public utilities as defined by the FPA and subject to extensive regulation by FERC. FERC s regulation of public utilities is comprehensive and governs such matters as rates, services, mergers, financings, affiliate transactions, market conduct and reporting. FERC is also responsible under PURPA for administering PURPA s requirements for QFs. PSEG, through its subsidiaries, owns several QF plants. QFs are subject to many, but not all, of the same FERC requirements as public utilities.

Expanded Merger Review Authority

PSEG, PSE&G, Power and Energy Holdings

The EP Act expanded FERC s authority to review mergers and acquisitions under the FPA. It extended the scope of FERC s authority to require prior FERC approval regarding transactions involving certain transfers of generation facilities, certain holding company transactions, and utility mergers and consolidations having a value in excess of $10 million. The EP Act requires that FERC, when reviewing proposed transactions, examine cross-subsidization and pledges or encumbrances of utility assets. PSEG, PSE&G, Power and Energy Holdings are unable to predict the effect of this authority on any potential future transactions in which they may be involved.

Compliance

Reliability Standards

PSEG, PSE&G, Power and Energy Holdings

The EP Act required FERC to empower a single, national Electric Reliability Organization (ERO) to develop and enforce national and regional reliability standards for the U.S. bulk power system. FERC has designated the North American Electric Reliability Corporation (NERC) as this ERO. NERC has filed with FERC delegation agreements that would in turn delegate, to a significant degree, the enforcement of such reliability standards to eight regional reliability councils approved by NERC, such as ReliabilityFirst. Thus, the relationship between NERC and the regional reliability councils (responsible for reliability standards compliance within a particular geographic region) is a contractual one. PSE&G s transmission assets, and most of Power s generation assets, are located within the geographic scope of Reliability First, and PSEG s remaining domestic assets, including the New York, Connecticut and Texas generating assets, are within the scope of other regional reliability councils such as NPCC and ERCOT.

After being designated as an ERO, NERC asked FERC to approve a set of proposed mandatory Reliability Standards, many of which mirrored existing, voluntary standards. On October 20, 2006, FERC issued a Notice of Proposed Rulemaking (NOPR), which proposed to approve 83 of the 107 filed standards and asked for additional information regarding the remaining 24 standards. Compliance with these 83 standards, enforcement of which will largely be delegated to the regional reliability councils such as Reliability First, is mandatory and sanctions may attach for non-compliance. Pursuant to the EP Act, FERC has the ability to impose penalties of up to $1 million a day for violations of these standards. Under the NOPR, which is not yet a Final Rule, compliance with these Standards will be required by the commencement of the 2007 summer peak season. These Standards are applicable to transmission owners and generation owners, and thus PSEG, PSE&G, Power and Energy Holdings (or their subsidiaries) will be obligated to comply with the Standards. PSEG, PSE&G, Power and Energy Holdings are currently evaluating all of the requirements imposed by the Standards and are preparing to ensure that they will be in compliance by FERC-required date. It should be noted in this regard that PSE&G s local control center (LCC) was the first control center voluntarily audited by NERC in January 2006 with respect to LCC readiness. NERC concluded in this audit that PSE&G has adequate facilities, processes, plans, procedures, tools, and trained personnel to effectively operate as an LLC within PJM and found no significant operational problems.

FERC Standards of Conduct

PSEG, PSE&G, Power and Energy Holdings

On January 18, 2007, FERC issued a NOPR which proposes to make certain changes to its Standards of Conduct applicable to both electric and natural gas transmission providers. The NOPR was issued in response to a decision by the United States Court of Appeals of the District of Columbia, which vacated FERC s existing Standards of Conduct as they applied to natural gas pipelines. The NOPR, however, proposes changes to the Standards of Conduct for both natural gas and electric providers Some of the proposed changes include modifying the definition of Energy Affiliate and thereby changing the scope of applicability of the Standards of Conduct, changing the regulations with respect to the permissible tasks of shared employees (employees that may be shared by both the Transmission Provider and the Energy Affiliates) and modifying the information disclosure regulations. PSE&G is currently subject to FERC s Standards of Conduct as a Transmission Provider and subsidiaries of Power and Energy Holdings are subject to the Standards of Conduct as Energy Affiliates. Thus, FERC s proposed changes may have an impact on PSEG, PSE&G, Power and Energy Holdings and the interactions between these entities, although its impact is not clear at this time. PSEG is currently evaluating the NOPR and will file comments to the same prior to FERC issuing a Final Rule. The outcome of this proceeding cannot be predicted at this time.

Transmission Rates and Cost Allocation

PSEG, PSE&G and Power

PJM Schedule 12 Cost Allocation for Regional Transmission Expansion Planning(RTEP) Projects

On January 5, 2006, PJM proposed cost allocation recommendations for new transmission projects pursuant to Schedule 6 of its FERC-approved Operating Agreement and Schedule 12 of its Open Access Transmission Tariff (Tariff). PJM identified the Responsible Customers that would be required to pay for certain transmission upgrades approved through PJM s Regional Transmission Expansion Planning (RTEP) process and the percentage of the project cost that would be allocated to such Responsible Customers. This was the first filing by PJM pursuant to these new cost allocation mechanisms and it included (i) large cost allocations to eastern load as a result of proposed construction in the western and southern portions of PJM and (ii) allocations to merchant transmission projects such as Neptune Regional Transmission System, LLC. On May 26, 2006, FERC issued an order that accepted and suspended PJM s cost allocation filing, made the filing effective subject to refund as of May 30, 2006 and established a hearing and settlement judicial procedure.

In addition, on May 4, 2006, PJM made a second RTEP cost allocation filing at FERC, addressing cost allocations to Responsible Customers associated with additional RTEP projects. PSEG protested the filing, objecting to, among other things, PJM s netting of cost impacts within a PJM zone to allocate RTEP costs and PJM s failure to consider the impact of certain adjustments in determining zonal cost allocation.

On July 19, 2006, FERC consolidated PJM s January 5, 2006 and May 4, 2006 filings that propose to allocate the costs of new transmission projects that PJM has directed to be built through its RTEP process. On July 21, 2006, PJM submitted to FERC a further proposal to allocate the costs of an additional group of new transmission projects that PJM has directed be built through its RTEP. The July 21, 2006 filing includes allocations for the $850 million, 200-mile 500 kV Loudon transmission line which runs from Allegheny Power s service territory, through West Virginia to Northern Virginia, as well as many other transmission projects in the PJM region. This proceeding was consolidated with the other two PJM cost allocation filings and was then the subject of settlement proceedings before a ALJ. Settlement discussions terminated in November 2006 and, on November 7, 2006, the proceedings were set for hearing, with a hearing to commence no later than June 19, 2007. PJM has used the same allocation methodology to identify which load should pay for these new transmission projects through regulated transmission rates. PSEG is actively participating in this proceeding, as the cost allocation methodology used by PJM may result in a disproportionate allocation of costs to loads in the eastern portion of PJM. However, assuming continued pass-through of transmission charges to retail customers, neither Power nor PSE&G are expected to be impacted by the allocation of Schedule 12 charges. PSEG, PSE&G and Power are unable to predict the outcome of this hearing at this time.

Regional through and out rates (RTOR)

RTOR are separate transmission rates for transactions where electricity originated in one transmission control area is transmitted to a point outside that control area. Both the Midwest Independent Transmission System Operator, Inc. (MISO) and PJM charged RTORs through December 1, 2004. FERC approved a new regional rate design, which became effective December 1, 2004 for the entire PJM/MISO region and approved the continuation of license plate rates and a transitional Seams Elimination Charge/Cost Adjustment/Assignment (SECA) methodology effective from December 1, 2004 through March 2006.

On February 10, 2005, FERC issued an order that accepted various SECA filings, established December 2004 as the effective date for the SECA rates, made them subject to refund and surcharge, and established hearing procedures to resolve the outstanding factual issues raised in the filings and the responsive pleadings.

A trial-type hearing was held in May 2006, encompassing a review of the actual amount of lost revenues to be recovered via the SECA mechanism. On August 10, 2006, the ALJ issued an initial decision finding that the rate design for the recovery of SECA charges is flawed, and that the SECA rate charges are therefore unjust, unreasonable and unduly discriminatory. FERC has not yet issued an order on review of the ALJ initial decision. In addition, in March 2006, PSE&G and Power entered into a settlement with a limited group of parties in PJM, which settlement was certified to FERC, under which the parties have agreed to pay and collect reductions of SECA revenues. On October 12, 2006, the limited settlement agreement was expanded to include additional parties and on January 18, 2007, an additional settlement agreement was entered into with certain MISO parties. FERC has not yet acted to approve the March, October or January SECA settlements. Due to the uncertainty of this proceeding, PSE&G has continued to defer the collection of any SECA revenues on its books. At the present time, PSEG, PSE&G and Power do not anticipate any adverse impact as a result of the SECA decision.

PJM Long-Term Transmission Rate Design

On May 31, 2005, FERC issued an order addressing the recovery of costs for transmission upgrades designated through PJM s RTEP process. Among other matters, FERC s order responded to a proposal to continue PJM s current rate design, under which transmission customers pay rates within the particular transmission zone in which they take service. FERC concluded that the existing rate design may not be just and reasonable and it established a hearing to examine the justness and reasonableness of continuing PJM s modified zonal rate design. Certain entities filed proposals with FERC on September 30, 2005 for alternative rate designs for the PJM region. PSE&G, as part of a coalition of potentially affected PJM transmission owners, filed answering testimony on November 22, 2005 that supported continuation of the zonal rate design in PJM.

A hearing was held in April 2006 and on July 13, 2006, a FERC ALJ issued a decision concluding that the existing PJM modified zonal rate design for existing facilities has been shown to be unjust and unreasonable, and should be replaced with a postage stamp rate design (single postage stamp rate paid by all transmission customers in PJM) for such facilities to be effective April 1, 2006. To mitigate rate impacts, the ALJ determined that the rate design should be phased in, so that no customer receives greater than a 10% annual rate increase. The ALJ also determined that the existing process for allocating costs of new transmission projects pursuant to Schedule 6 of PJM s Operating Agreement and Schedule 12 of the PJM Tariff was just and reasonable. Briefs on exceptions to the ALJ s initial decision and reply briefs were filed in this proceeding challenging the decision to find the existing rate design unjust and unreasonable, the appropriateness of imposing a postage stamp rate design, the decision as to the appropriateness of applying the current Schedule 6 and Schedule 12 process for allocating costs of new transmission projects and the phase-in of the new rate design. FERC has not yet issued a decision on review of the ALJ s initial decision. Should FERC ultimately approve this postage stamp rate design on review of the ALJ s initial decision, or adopt one or a combination of the alternative rate designs proposed, assuming continued pass-through of transmission charges to retail customers, PSEG s and PSE&G s results of operations could be adversely impacted with no adverse impact currently anticipated for Power.

Market Power, Market Design and Capacity Issues

PSEG, PSE&G and Power

Market Power

Under FERC regulations, public utilities may sell power at cost-based rates or apply to FERC for authority to sell at market-based rates (MBR). PSE&G, ER&T and certain other subsidiaries of Fossil and Energy Holdings have applied for and received MBR authority from FERC, which permits them to sell power into the wholesale market at market-based rates. FERC requires that holders of MBR tariffs file an update, on a triennial basis, demonstrating that they continue to lack market power. On November 30, 2006, PSE&G and ER&T filed their respective triennial updated market power reports with FERC. FERC has not yet acted on these updated market power reports.

On May 19, 2006, FERC issued a NOPR concerning the standards to be used by FERC in granting market-based rate authority. The proposed regulations would adopt, in most respects, FERC s current standards. In its NOPR, FERC suggests certain changes, such as in the areas of cost-based market power mitigation, modifications to the horizontal (generation) market power screens, and clarifications to existing vertical market power screens. On September 20, 2006, PSE&G and Power submitted comments in this NOPR proceeding. FERC has not yet issued a Final Rule in this rulemaking proceeding. The outcome of this proceeding and its impact on PSEG, PSE&G, Power and Energy Holdings cannot be predicted at this time, but Power does not expect the new rules to disqualify its MBR authority. However, no assurances can be given.

FERC s MBR policies and the wholesale electricity markets which they help support are evolving and subject to change. Specifically, on December 19, 2006, the United States Court of Appeals for the Ninth Circuit overturned certain FERC orders in a series of cases, to which PSEG was not a party, which involved long term wholesale contracts entered into during the California Energy Crisis and, by so doing, seriously undermined the contract sanctity doctrine that had previously been applied to preserve these contracts. Moreover, the court held that FERC s MBR policies are insufficient to establish that agreements reached under MBR tariffs are just and reasonable at the outset. Thus, the fact that a contract is entered into under a MBR tariff may not render it immune from just and reasonable review by FERC. This case will likely be appealed to the U.S. Supreme Court but represents a significant development and is one that will be monitored for its impact on the wholesale electric market in the future.

RMR Status

PJM

Although applicable tariff provisions differ from region to region, RMR tariff provisions provide compensation to a generation owner when a unit proposed for retirement must continue operating for reliability purposes. In September 2004, Power filed notice with PJM that it was considering the retirement of seven generating units in New Jersey, effective December 7, 2004, due to concerns about the economic viability of the units under the then current market structure. The units that were being considered for retirement were Sewaren 1, 2, 3 and 4, Kearny 7 and 8 and Hudson 1. Kearny 7 and 8 were retired in 2005. In response to Power s filed notice, PJM identified certain system reliability concerns associated with the proposed retirements.

Effective February 24, 2005, subject to refund and hearing, Power began to collect a monthly fixed payment of $3.3 million, pre-tax, net of operating margins for the Sewaren 1, 2, 3 and 4 and Hudson 1 units. A detailed settlement was filed with FERC on September 23, 2005 that permits Power to recover annual fixed costs of approximately $19 million and $14.5 million, pre-tax, for the Sewaren and Hudson units, respectively, plus reimbursements of Power s expenditures in connection with certain construction at the units that are necessary to maintain reliability, offset by certain revenues earned in PJM s energy market.

FERC accepted this settlement retroactive to February 24, 2005. On March 28, 2006, Power filed a refund report with FERC pursuant to which Power refunded $11 million to PJM, although most of this refund related to the timing of payments under the settlement agreement and thus will be repaid to Power, with carrying charges, at a later date. FERC did not issue a public notice requesting comments on the report and no party has made any objections or other comments with respect to the report. Power is in the process of extending its RMR contract for Hudson Unit 1 through September 2010. For additional information, see Note 12. Commitments and Contingent Liabilities of the Notes.

New England

In the New England electricity market, many owners of generation facilities have filed with FERC for RMR treatment under the NEPOOL Open Access Transmission Tariff. If FERC grants RMR status for a generation facility located in the New England market, the owner is entitled to receive cost-of-service treatment for its facility for the duration of an RMR contract that it enters into with ISO New England Inc. On November 17, 2004, PSEG Power Connecticut LLC (Power Connecticut), a wholly owned indirect subsidiary of Power, filed a request for RMR treatment for the New Haven Harbor generation station and Unit 2 at the Bridgeport Harbor generation station. FERC issued an order on January 14, 2005, subject to refund and hearing which allowed Power Connecticut to begin collecting monthly fixed payments of approximately $1.6 million and $3.9 million, pre-tax, for reliability services provided by the Bridgeport Harbor Station, Unit 2 and the New Haven Harbor Station, respectively, net of operating margins. On June 17, 2005, Power Connecticut filed revised studies supporting monthly recovery of $1.3 million and $3.3 million, pre-tax, for the Bridgeport Harbor and New Haven Harbor units, respectively.

On April 21, 2006, Power Connecticut, the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel and ISO New England Inc. filed with FERC a Joint Stipulation and Settlement Agreement and Motion for Expedited Consideration. The Joint Stipulation and Settlement settled all matters associated with the RMR agreements filed by Power Connecticut for its Bridgeport Harbor 2 and New Haven Harbor stations. Among other things, the settlement provides for monthly fixed payments of approximately $1 million for Bridgeport Harbor and $3 million for New Haven Harbor. The only disputed issues concern the standard of review applicable to certain types of potential tariff changes that could be filed in the future. No party has challenged the settlement rates proposed to become effective. The ALJ certified the settlement to FERC on June 21, 2006 as a contested offer of settlement. It is anticipated that the settlement will be approved as certified or, if modified, will not be modified in a manner that adversely affects the settlement rates. However, Power Connecticut cannot predict a final outcome at this time, as FERC has not yet acted to approve the settlement.

PJM Reliability Pricing Model (RPM)

On August 31, 2005, PJM filed its RPM with FERC. The RPM constitutes a locational installed capacity market design for the PJM region, including a forward auction for installed capacity priced according to a downward-sloping demand curve and a transitional implementation of the market design. FERC issued an order on April 20, 2006 that accepted most of the core concepts of the RPM filing with an implementation date of June 1, 2007. The April 20, 2006 order set certain details of the filing for paper hearing and technical conference procedures including the slope of the demand curve and the mechanism for identification of the locational capacity zones. Such hearing and technical conference procedures have now been completed. Also, commencing in June 2006, settlement discussions mediated by a FERC ALJ commenced at the request of certain intervenors. A final settlement was filed with FERC on September 29, 2006 with a requested approval date of no later than December 22, 2006. PSE&G and Power filed comments to the settlement supporting the basic structural elements of the RPM proposal but nonetheless requesting certain modifications which, in their view, would better promote the adequacy of generation reserves on a cost-effective basis. On December 22, 2006, FERC issued an order approving the September 29 settlement, with certain conditions. FERC s approval of this settlement is expected to have a favorable impact on generation facilities located in constrained locational zones. The final revenue impact on Power of the settlement approved in the December 22, 2006 FERC order could result in incremental margin of $100 million to $150 million in 2007, with higher increases in future years as the full year impact is realized and existing capacity contracts expire. The April 20, 2006 order remains subject to rehearing requests filed by several parties. Moreover, on January 22, 2007, PSEG as well as other parties to the proceeding filed for rehearing of the December 22, 2006 order.

Given the pending rehearing requests and the likelihood of eventual judicial appeals, PSEG, PSE&G and Power are unable to predict the outcome of this proceeding.

Forward Capacity Market (FCM) Settlement in New England

On January 31, 2006, certain interested market participants in New England agreed to a settlement in principle of litigation regarding the design of the region s market for installed capacity, which would institute a transition period leading to the implementation of a new market design for capacity as early as 2010. Commencing in December 2006, all generators in New England began receiving fixed capacity payments that escalate gradually over the transition period. RMR contracts, such as Power s, would continue to be effective until the implementation of the new market design. The new market design is expected to consist of a forward auction for installed capacity that is intended to recognize the locational value of generators on the system, and is expected to contain incentive mechanisms to encourage generator availability during generation shortages. During the transition period, these payments are expected to benefit Power s Bridgeport Harbor 2 plant. The final version of the settlement was filed with FERC on March 6, 2006 and was approved by order dated June 16, 2006 finding that, as a package, the settlement represents a just and reasonable outcome. The settlement was contested by certain parties and a rehearing was sought of the June 16, 2006 order. On October 31, 2006, FERC denied rehearing and accepted the FCM settlement in a final order; the order, however, remains subject to judicial challenge.

Transmission Infrastructure

PSEG, PSE&G, and Power

RTEP

On September 8, 2006, PJM filed with FERC a proposal that would significantly modify its regional transmission planning process for economic transmission planning. Currently, the PJM RTEP identifies transmission that is needed to address reliability, operational performance and economic needs of the PJM region based on historic congestion. The PJM proposal sought to expand the economic portion of the RTEP by forecasting economic congestion over its transmission planning horizon, which, in 2006, PJM modified from five to 15 years. PSE&G and Power filed a protest to the PJM proposal requesting that FERC reject PJM s proposal or set it for hearing. On November 21, 2006, FERC issued an order conditionally accepting PJM s proposed changes to the RTEP for economic transmission planning. FERC directed PJM to make certain modifications to its proposal, including requiring PJM to make a compliance filing within 120 days identifying how it will weigh and/or combine the metrics it proposes for determining the net benefits of a particular project and to make a compliance filing within 90 days elaborating on the criteria it will use to determine if an alternative project is more economic than an RTEP project. Nonetheless, PJM s changes to its economic transmission planning process may result in the establishment of a preference for rate-based transmission solutions to address congestion, as opposed to reliance on private investment and competitive non-transmission market solutions. PSE&G and Power filed for rehearing of the November 21, 2006 FERC order on December 21, 2006. FERC has not yet issued an order on rehearing. PSEG, PSE&G and Power are unable to predict the final outcome of this proceeding.

DOE Congestion Study

On August 8, 2006, the DOE issued a National Electric Transmission Congestion Study (Congestion Study), as directed by Congress in the EP Act. This Congestion Study identified two areas in the U.S. as critical congestion areas; one of the areas is the region between New York and Washington, D.C. Under the EP Act, the DOE has the ability to designate transmission corridors in these critical congestion areas, to which FERC back-stop transmission siting authority will attach. Thus, corridor designation may facilitate the construction of rate-based transmission projects to address congestion in these corridors. The DOE has not yet designated any transmission corridors as a result of this Congestion Study but will likely do so in the first quarter of 2007. PSE&G and Power filed comments to the Congestion Study, in which they contended that the Congestion Study contained several analytical flaws. PSEG, PSE&G and Power are unable to predict the outcome of this proceeding at this time.

LDV Complaint Proceeding

On December 30, 2004, Jersey Central Power & Light Company (JCP&L) filed a complaint at FERC against the other four signatories, including PSE&G, to the Lower Delaware Valley (LDV) Transmission System Agreement, which expires in 2027 and governs the construction of, and investment in, certain 500 kV transmission facilities in New Jersey. In the complaint proceeding, JCP&L seeks to terminate its payment obligations to the other contract signatories. A hearing was conducted in this proceeding in November 2006 and an initial decision is expected by the ALJ in March 2007. In this litigation, JCP&L is not only seeking to terminate its payment obligations to PSE&G of approximately $3 million per year through 2027, but also to receive credit from PSE&G and the other LDV Agreement parties for transmission facilities previously constructed by JCP&L in New Jersey; if the ALJ were to accept all of JCP&L s crediting arguments, an outcome that is unlikely, PSE&G would owe approximately $5 million to JCP&L under the LDV Agreement. PSE&G cannot predict the outcome of this proceeding at this time.

PJM Strategic Initiative

In the fourth quarter of 2006, PJM launched a strategic initiative to more specifically define its role in the evolving wholesale energy markets. As part of this initiative, PJM sought comments from its members, including PSEG, on a number of items, including whether PJM should consider splitting its wholesale market operations from its transmission grid operations and whether PJM should consider changes to its current corporate governance structure. PJM has since pulled back from its idea of splitting market and grid operations but continues to consider whether there is a need to modify aspects of its current market and governance structure. PSEG will continue to actively participate in these discussions.

NRC

PSEG and Power

Nuclear s operation of nuclear generating facilities is subject to continuous regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. Power has recently commenced the process to extend the operating licenses for the Salem and Hope Creek facilities. The current operating licenses of Power s nuclear facilities expire in the years shown below:

Facility	Year
Salem 1	2016
Salem 2	2020
Hope Creek	2026
Peach Bottom 2	2033
Peach Bottom 3	2034

Nuclear Safety Issues

In January 2004, the NRC issued a letter requesting Power to conduct a review of its Salem and Hope Creek nuclear generation facilities to assess the workplace environment for raising and addressing safety issues. Power responded to the letter in February 2004 and had independent assessments of the work environment at both facilities performed which concluded that Salem and Hope Creek were safe for continued operations, but also identified issues that needed to be addressed. These facilities were under enhanced oversight by the NRC related to the work environment until August 31, 2006, at which time the NRC provided a letter informing Power that its mid-cycle performance review had concluded that the substantive cross-cutting issue in the safety-conscious work environment area at Salem and Hope Creek was closed. The NRC has restored Salem and Hope Creek to normal oversight levels.

Recirculation Pump

In a letter to the NRC dated January 9, 2005, Power committed to install vibration-monitoring equipment on Hope Creek s B Reactor Recirculation Pump prior to the unit s return to service to address pump vibration concerns and replace the pump s shaft during the next refueling outage or any sooner outage of sufficient duration. This commitment was the subject of a January 11, 2005 Confirmatory Action Letter from the NRC. The shaft was replaced during the Hope Creek outage in April 2006. On April 20, 2006, the NRC issued a Closure of Confirmatory Action Letter indicating that all of the commitments were completed.

Other

PSE&G

Investment Tax Credits (ITC)

As of June 1999, the Internal Revenue Service (IRS) had issued several private letter rulings (PLRs) that concluded that the refunding of excess deferred tax and ITC balances to utility customers was permitted only over the related assets regulatory lives, which were terminated upon New Jersey s electric industry deregulation. Based on this fact, PSEG and PSE&G reversed the deferred tax and ITC liability relating to PSE&G s generation assets that were transferred to Power, and recorded a $235 million reduction of the extraordinary charge in 1999 due to the restructuring of the utility industry in New Jersey. PSE&G was directed by the BPU to seek a PLR from the IRS to determine if the ITC included in the impairment write-down of generation assets could be credited to customers without violating the tax normalization rules of the Internal Revenue Code. PSE&G filed a PLR request with the IRS in 2002.

On December 21, 2005, the U.S. Department of the Treasury (Treasury) proposed new regulations for comment addressing the normalization of ITC, replacing regulations originally proposed in 2003. The new proposed regulations, if finalized, would not permit retroactive application. Accordingly, the IRS s conclusions in the above referenced PLRs would continue to remain in effect for all industry deregulations prior to December 21, 2005.

On April 26, 2006, the BPU issued an order to PSE&G revoking its previous instruction and directing PSE&G to withdraw its request for a PLR by April 27, 2006. The BPU asserted that the Treasury s proposed regulation project was the more appropriate authority to rely upon in deciding the ITC issue.

On May 1, 2006, PSE&G filed a motion for reconsideration with the BPU requesting that it modify its April 26, 2006 order to PSE&G to withdraw the PLR request. On May 5, 2006, the BPU denied PSE&G s motion for reconsideration and reiterated its order to withdraw the PLR request. On May 8, 2006, PSE&G filed a petition with the Appellate Court of New Jersey challenging the BPU s order to withdraw the PLR. On May 11, 2006, the IRS issued a PLR to PSE&G. The PLR concluded that none of the generation ITC could be passed to utility customers without violating the normalization rules. While the holding in the PLR is a favorable development for PSE&G, the outstanding Treasury regulation project could overturn the holding in the PLR if the Treasury were to alter the position set out in the December 21, 2005 proposed regulations. The issue cannot be fully resolved until the final Treasury regulations are issued.

On May 16, 2006, the BPU voted in favor of a special investigation and hearing before the BPU concerning PSE&G s actions leading up to receiving the PLR, specifically its failure to abide by the BPU order to withdraw the request. An order detailing such special investigation has not yet been issued and no investigation has begun.

On October 13, 2006, the Appellate Division of the Superior Court of New Jersey granted PSE&G s motion to dismiss PSE&G s appeal of the BPU s order to withdraw the PLR since PSE&G has already received the PLR. The court also determined that if the BPU seeks to take future action against PSE&G based on the alleged violation of its order, PSE&G can restart the appeal.

State Regulation

PSEG, PSE&G, Power and Energy Holdings

The BPU is the regulatory authority that oversees electric and natural gas distribution companies in New Jersey. PSE&G is subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service and the issuance and sale of securities. Power s partial ownership of generating facilities in Pennsylvania, as well as PSE&G s ownership of certain transmission facilities in Pennsylvania, are subject to regulation by the Pennsylvania Public Utility Commission (PAPUC), which oversees retail electric and natural gas service in Pennsylvania. PSE&G and Power are also subject to rules and regulations of the NJDEP and the New Jersey Department of Transportation (NJDOT).

As discussed below, various Power subsidiaries and Energy Holdings   subsidiaries are subject to some state regulation in other individual states where they operate facilities, including New York, Connecticut, Indiana, Texas, California, Hawaii and New Hampshire.

PUHCA Repeal

On August 1, 2005, the BPU initiated a proceeding to consider whether additional ratepayer protections were necessary in light of the repeal of PUHCA by the EP Act. The proceeding considered the BPU s current authority to protect utility ratepayers from risks associated with a utility being part of a holding company structure. The BPU determined that additional protections were necessary and commenced a two phase rulemaking to address its view of potential risks associated with a utility being part of a holding company structure. Phase I of the rulemaking effort resulted in the adoption of new regulations effective October 2, 2006, addressing the diversification activities of New Jersey utilities and their holding companies. These new rules impose a requirement that each New Jersey public utility and its holding company ensure that the aggregate assets of all nonutility activities in the holding company system do not exceed a defined percentage (25%) of the aggregate assets of the utility and utility- related assets in the holding company system without BPU consent. The rules broadly define utility-related activities to include such things as the production, generation, transmitting, delivering, storing, selling, marketing of natural gas, propane, electricity and other fuels to wholesale or retail customers, energy management services and sale of energy appliances. Both PSE&G and PSEG currently satisfy these requirements and expect to continue to satisfy them based on the companies   current business plans. However, constant monitoring will be required to ensure that the regulation is satisfied and to meet the annual certification process. The BPU is currently developing Phase II of the rulemaking in a stakeholder process. In Phase II the BPU is proposing new regulations that would increase the BPU s access to books and records, impose restrictions on service agreements between utilities and their affiliated service companies and impose additional requirements on utility board of director composition, utility participation in money pools and additional reporting obligations.

New Jersey Energy Master Plan

The Governor of New Jersey has recently directed the BPU, in partnership with other New Jersey agencies, to develop an energy master plan. State law in New Jersey requires that an energy master plan be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. In the Governor s directive regarding the energy master plan, the Governor established three specific goals: (1) reduce the State s projected energy use by 20% by the year 2020; (2) supply 20% of the State s electricity needs with certain renewable energy sources by 2020; and (3) emphasize energy efficiency, conservation and renewable energy resources to meet future increases in New Jersey electric demand without increasing New Jersey s reliance on non-renewable resources. In November, PSEG submitted a number of strategies designed to improve efficiencies in customer use and increase the level of renewable generation. During January and February 2007, PSEG has been actively involved in the broad-based constituent working groups created to develop specific strategies to achieve the goals and objectives. Public meetings on the energy master plan are expected take place during the first and second quarters of 2007, and a final plan is expected to be completed by October 2007. The outcome of this proceeding and its impact on PSEG, PSE&G and Power cannot be predicted at this time.

PSE&G and Power

BGS Auctions

All of New Jersey s EDCs jointly procure the supply to meet their BGS obligations through two concurrent auctions authorized by the BPU for New Jersey s total BGS requirement. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey s EDCs. Certain conditions are required to participate in these auctions. Energy suppliers must agree to execute the BGS Master Service Agreement, provide required security within three days of BPU certification of auction results and satisfy certain creditworthiness requirements.

In 2006, the BPU initiated a proceeding to review the annual BGS procurement process as well as the policy issues thereto for all of the New Jersey EDCs. In June 2006, the BPU ruled on certain issues regarding the acquisition of BGS for the period beginning in June 2007. The BPU agreed that a descending clock auction format should be used for the procurement of BGS-FP supply for 2007.

On July 10, 2006, PSE&G filed the Joint EDC proposal for the procurement of BGS for the period beginning June 1, 2007. This proposal includes a descending clock auction format to be held in February 2007 for the procurement of all BGS supply. On October 28, 2006, the BPU approved a descending clock auction format for BGS-FP and BGS-CIEP supply for the period beginning June 1, 2007. On December 22, 2006, the BPU approved the remainder of the items in the EDCs filing, without material changes. The BPU also directed the EDCs to remit all remaining retail margin monies previously collected from larger customers to the State Treasurer in January 2007, and to remit any future collections of the retail margin to the State Treasurer on a quarterly basis. In 2003, the BPU directed the EDCs to collect a 0.5 per kWh retail adder from all BGS customers greater than 750 kW. These monies were held in a regulatory liability account. For additional information see Note 5 Regulatory Matters and Note 12. Commitments and Contingent Liabilities of the Notes.

PSE&G

Electric Distribution Financial Review

Based on the Electric Base Rate Case approved in July 2003, PSE&G recorded a regulatory liability in the second quarter of 2003 by reducing its depreciation reserve for its electric distribution assets by $155 million and amortized this liability from August 1, 2003 through December 31, 2005. The $64 million annual amortization of this liability resulted in a reduction of Depreciation and Amortization expense. PSE&G filed for a $64 million (based on 2003 test year sales volumes) annual increase in electric distribution rates effective January 1, 2006, subject to BPU approval, including a review of PSE&G s earnings and other relevant financial information. Based on current sales volumes, the amount approximates $69 million.

On November 9, 2006, the BPU approved a settlement agreement reached by the parties to the proceeding authorizing a $22 million reduction to electric distribution rates, resulting in additional revenue to PSE&G of approximately $47 million annually based on current sales volumes.

The settlement includes a restriction against any further base rate changes becoming effective before November 15, 2009. In addition, PSE&G must file a joint electric and gas petition for any future base rate increases.

BGSS Filings

The parties to the 2005/2006 BGSS proceeding entered into a Stipulation in which the parties agreed that the BGSS Commodity Charge increases of September 1, 2005 and December 15, 2005 that were previously approved by the BPU on a provisional basis should become final. The BPU approved the Stipulation. In addition, all the remaining gas contract issues were also resolved and an amended Gas Requirements Contract was attached to the Stipulation and also approved by the BPU. The primary changes were the term was extended by five years and the default provision was changed from three days to one day.

PSE&G made its 2006/2007 BGSS filing on May 26, 2006. In this filing, PSE&G requested a reduction in annual BGSS gas revenues of approximately $19.7 million (excluding losses and New Jersey Sales and Use Tax) or approximately a 1.0% decrease to be implemented for service rendered on and after October 1, 2006 or earlier. Additionally, PSE&G requested an increase in its Balancing Charge. The combined impact of both changes for the class average residential heating customer is an increase in the winter monthly bills of approximately 0.1%; however, on an annual basis the impact is a decrease of approximately 0.2%.

The parties entered into a Stipulation to make the filed BGSS rate effective October 1, 2006 on a provisional basis. However, since the time of the filing, prices of gas futures have dropped significantly and as a result, additional BGSS data has been requested by and provided to the BPU. Settlement discussions with the BPU Staff were completed and a new Stipulation, dated October 27, 2006, was executed by the parties. This new Stipulation was approved by the BPU and results in a decrease in annual BGSS revenues of approximately $120 million, which is approximately a 6%

reduction in a typical residential gas customer s bill. The new BGSS rate became effective on November 9, 2006. The Stipulation did not include any change in the Balancing Charge.

The parties entered into a second Stipulation, which addresses the Balancing Charge only. The BPU Staff recommended a lower Balancing Charge than proposed by the Company and received agreement from Rate Counsel. The parties executed the Stipulation for the lower rate and BPU approval was received on January 17, 2007.

Remediation Adjustment Clause (RAC) Filing

PSE&G is engaged in a program to address potential environmental concerns regarding its former Manufactured Gas Plant (MGP) properties in cooperation with and under the supervision of NJDEP. The costs of the program are recovered through the Remediation Adjustment Clause (RAC). The RAC addresses costs in annual periods ending July 31st of each year. The expenditures in each RAC period are recovered over seven years. The costs of the program, including interest, are deferred and amortized as collected in revenues.

On December 5, 2005 the BPU approved for recovery $18 million for the RAC-12 remediation expenditures incurred from August 1, 2003 through July 31, 2004. No change in the RAC recovery factor was required.

In February 2007, PSE&G submitted its RAC-13 and RAC-14 filings with the BPU. In these filings, PSE&G seeks an order finding that the $71 million of RAC program costs incurred during the two-year period, August 1, 2004 through July 31, 2006, are reasonable and are available for recovery. PSE&G proposes that the current gas and electric RAC rates be reduced by approximately $18 million annually, effective July 1, 2007.

Gas Base Rate Case

On September 30, 2005, PSE&G filed a petition with the BPU seeking an overall 3.78% increase in its gas base rates to cover the cost of gas delivery to be effective June 30, 2006. Approximately $55 million of the $133 million request was for an increase in book depreciation rates.

On November 9, 2006, the BPU approved a settlement agreement reached by the parties to the proceeding. The agreement provides for an annual increase in gas revenues of $40 million or approximately 1.1%. In addition, the settlement provides for an adjustment to lower book depreciation and amortization expense for PSE&G by approximately $26 million annually and the amortization of accumulated cost of removal that will further reduce depreciation and amortization expense by $13 million annually for five years.

The settlement includes a restriction against any further base rate changes becoming effective before November 15, 2009. In addition, PSE&G must file a joint electric and gas petition for any future base rate increases.

Societal Benefits Clause (SBC) Filing

On August 12, 2005, PSE&G filed a motion with the BPU seeking approval of changes in its electric and gas SBC rates and its electric non-utility generation transition charge (NTC) rates. For electric customers, the rates proposed were designed to recover approximately $106 million in SBC revenues offset by lower NTC rates of $93 million beginning January 1, 2006. For gas, the rates proposed were designed to recover approximately $10 million in SBC revenues. In 2006, PSE&G filed updates to its filing, modifying its requested changes to electric SBC/NTC rates and gas SBC rates. Public hearings were held and settlement discussions began on outstanding issues. On January 19, 2007, settlement documents were filed with the ALJ, which upon approval, would result in an annual increase of approximately $16 million in electric SBC/NTC revenues and $12 million in gas SBC revenues.

Deferral Audit

The BPU Energy and Audit Division conducts audits of deferred balances. A draft Deferral Audit Phase II report relating to the 12-month period ended July 31, 2003 was released by the consultant to the BPU in April 2005. The draft report addressed the SBC, Market Transition Charge (MTC) and Non-Utility Generation (NUG) deferred balances. The consultant to the BPU found that the Phase II deferral balances complied in all material respects with the BPU orders regarding such deferrals, the consultant noted that the BPU Staff had raised certain questions with respect to the reconciliation method PSE&G employed in calculating the overrecovery of its MTC and other charges during the Phase I and Phase II four-year transition period. For additional information regarding PSE&G s Deferral

Audit, see Note 12. Commitments and Contingent Liabilities of the Notes.

Gas Purchasing Strategies Audit

In January 2007, the BPU has issued an RFP to solicit bid proposals to engage a contractor to perform an analysis of the gas purchasing practices and hedging strategies of the four New Jersey gas distribution companies (GDC s), including PSE&G. The primary focus will be to examine and compare the financial and physical hedging policies and practices of each GDC and to provide recommendations for improvements to these policies and practices. PSE&G cannot predict the outcome of this process.

New Jersey Clean Energy Program

In December 2004, the BPU has approved a funding requirement for each New Jersey utility applicable to Renewable Energy and Energy Efficiency programs for the years 2005 through 2008. The State of New Jersey has awarded contracts to two market managers, TRC Energy Services and Honeywell Utility Solutions to take over program management functions from the utilities. This transition is now expected to take place in the first half of 2007. For additional information regarding PSE&G s Clean Energy Program, see Note 12. Commitments and Contingent Liabilities of the Notes.

Power

Connecticut

Legislation has been introduced in the Connecticut General Assembly that would impose a tax on electric generators of 50% on earnings above a 20% return on equity. Proceeds from this proposed windfall profits tax would be used to provide consumer rate relief. Legislation also has been introduced that would allow the state s electric utility companies to build and place into rate base up to 300 megawatts of peaking electric generation.

Neither PSEG nor Power is able to predict whether any of such proposals will be enacted into law or their impact, if any, or whether similar initiatives may be considered in other jurisdictions.

Connecticut Department of Public Utility Control (DPUC)

To reduce the impact of federally-mandated congestion charges on Connecticut ratepayers, Connecticut has launched a procurement process to facilitate the development of incremental generation capacity, as authorized by legislation which permits the DPUC to establish a competitive procurement process intended to encourage new supply-side and demand-side resources. Specifically, the DPUC is required to develop and issue a request for proposals (RFP) to solicit the development of long-term projects, with local distribution companies serving as the counterparties to these contracts. The impact of this RFP process on Power Connecticut s assets is unclear at the present time.

Energy Holdings

Texas

Global s generation business in Texas (TIE) is a merchant generation business that participates, through its subsidiaries, Odessa-Ector Power Partners, L.P. (Odessa) and Guadalupe Power Partners, LP (Guadalupe), in the Texas wholesale energy market administered by ERCOT. Under the regulation of the Public Utility Commission of Texas, ERCOT performs three main roles in managing the electric power grid and marketplace: ensuring that the grid can accommodate scheduled energy transfers, ensuring grid reliability, and overseeing retail transactions. While neither TIE, Odessa nor Guadalupe are public utilities subject to the jurisdiction of FERC, they are subject to FERC jurisdiction for purposes of complying with NERC s Reliability Standards (see discussion in Federal Regulation Compliance Reliability Standards).

Like other energy markets, energy prices in ERCOT have risen over the past few years due, in large measure, to higher fuel costs. In an attempt to lower electricity prices, the legislature in Texas is currently examining proposals for draft legislation that could affect the Texas market. PSEG does not know at this time if any legislation will ultimately pass, or if it does, what its effect will be on Global s generation business in Texas.

International Regulation

Energy Holdings

Global

Global s electric distribution facilities in South America are rate-regulated enterprises. Rates charged to customers are established by government authorities and are viewed by Global as currently sufficient to cover operating costs and provide a return on its investments. Global can give no assurances that future rates will be established at levels sufficient to cover such costs, provide a return on its investments or generate adequate cash flow to pay principal and interest on its debt or to enable it to comply with the terms of its debt agreements.

Chile

Distribution companies in Chile, including Chilquinta Energia S.A. (Chilquinta) and associated companies, Sociedad Austral de Electricidad S.A. (SAESA) and other members of the SAESA Group, are subject to rate regulation by the Comision Nacional de Energia (CNE), a national governmental regulatory authority. The Chilean regulatory framework has been in existence since 1982, with rates set every four years based on a model company for each typical concession area. The tariff which distribution companies charge to regulated customers consists of two components: the actual cost of energy purchased and an additional amount to compensate for the value added in distribution (DVA tariff). The DVA tariff considers allowed losses incurred in the distribution of electricity, administrative costs of providing service to customers, costs of maintaining and operating the distribution systems and an annual return on investment between 6% to 14% over inflation applied to the replacement cost of distribution assets. Changes in electricity distribution companies cost of energy are passed through to customers, with no impact on the distributors margins (equal to the DVA tariff). Therefore, distributors, including members of the SAESA Group and Chilquinta, should not be affected by changes in the generation sector which affect prices. The most recent tariff adjustments for members of the SAESA Group and Chilquinta occurred in 2004 and have been reviewed and approved by the CNE.

In addition, the first auction for long-term supply contracts for Chilean distribution companies was simultaneously conducted during 2006. SAESA and Chilquinta were successful in contracting for approximately 2,900 Gwh/yr and 800 Gwh/yr, respectively from various generation companies to supply their regulated customers needs starting in 2010 and continuing through 2020 and 2025 for SAESA and Chilquinta, respectively. A second auction process for additional needs for Chilquinta (approximately 1,800 Gwh/year) will be held during 2007.

Peru

Distribution companies in Peru, including Luz del Sur S.A.A. (LDS), are subject to tariff regulation by the Organismo Supervisor de la Inversion en Energia, a national governmental regulatory authority. The Peruvian regulatory framework has been in existence since 1992, with tariffs set every four years based on a model company. The tariff which distribution companies charge to regulated customers consists of two components: the actual cost of energy purchased plus an additional amount to compensate for the DVA tariff. The DVA tariff considers allowed losses incurred in the distribution of electricity, administrative costs of providing service to customers, costs of maintaining and operating the distribution systems and an annual return on investment of 8% to 16% over inflation, based on the replacement cost of distribution assets. Changes in electricity distribution companies cost of energy are passed through to customers, with no impact on the distributors margins (equal to the DVA tariff). Therefore, distributors, including LDS, should not be affected by changes in the generation sector, which affect prices. The most recent tariff adjustments for LDS occurred in connection with the 2005 tariff-setting process. New tariffs were effective as of November 1, 2005.

In addition, in accordance with local regulations, an auction was conducted at the end of December 2006 for prospective energy supply requirements for LDS. The total amount bid by Peruvian power producers was 650 MW of capacity. This supply combined with the contracts still in force are expected to be sufficient to meet LDS s energy supply needs for 2007. In order to secure the growing supply needs for 2008 and beyond, management plans to conduct additional energy supply auctions, as necessary, during 2007. Management is concurrently exploring the feasibility of other forms of bilateral supply contracts, as well as advocating the extension of a law beyond December 2007, which currently allows LDS and other distribution companies without supply contracts, to draw energy from the grid, as required, at regulated prices to satisfy the regulated market s demand.

SEGMENT INFORMATION

Financial information with respect to the business segments of PSEG, PSE&G, Power and Energy Holdings is set forth in Note 18. Financial Information by Business Segment of the Notes.

ENVIRONMENTAL MATTERS

PSEG, PSE&G, Power and Energy Holdings

Federal, regional, state and local authorities regulate the environmental impacts of PSEG s operations within the U.S. Laws and regulations particular to the region, country or locality where PSEG s operations are located govern the environmental impacts associated with its foreign operations. For both domestic and foreign operations, areas of regulation may include air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate and other matters.

To the extent that environmental requirements are more stringent and compliance more costly in certain states where PSEG operates compared to other states that are part of the same market, such rules may impact its ability to compete within that market. Due to evolving environmental regulations, it is difficult to project expected costs of compliance and its impact on competition. For additional information related to environmental matters, see Item 3. Legal Proceedings.

PSEG, Power and Energy Holdings

Air Pollution Control

The Federal Clean Air Act (CAA) and its implementing regulations require controls of emissions from sources of air pollution and also impose record keeping, reporting and permit requirements. Facilities in the U.S. that Power and Energy Holdings operate or in which they have an ownership interest are subject to these Federal requirements, as well as requirements established under state and local air pollution laws applicable where those facilities are located. Capital costs of complying with air pollution control requirements through 2010 are included in Power s estimate of construction expenditures in Item 7. MD&A Capital Requirements.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a major modification, as defined in the regulations. The Federal government may order companies not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties of up to approximately $27,500 for each day of continued violation.

The EPA and the NJDEP issued a demand in March 2000 under the CAA requiring information to assess whether projects completed since 1978 at the Hudson and Mercer coal-burning units were implemented in accordance with applicable PSD/NSR regulations. Power completed its response to requests for information and, in January 2002, reached an agreement with the NJDEP and the EPA to resolve allegations of noncompliance with PSD/NSR regulations. Under that agreement, over the course of 10 years, Power agreed to install advanced air pollution controls to reduce emissions of Sulfur Dioxide (SO2), Nitrogen Oxide (NOx), particulate matter and mercury from the coal-burning units at the Mercer and Hudson generating stations to ensure compliance with PSD/NSR. Power also agreed to spend at least $6 million on supplemental environmental projects and pay a $1 million civil penalty. The agreement resolving the NSR allegations concerning the Hudson and Mercer coal-fired units also resolved a dispute over Bergen 2 regarding the applicability of PSD requirements and allowed construction of the unit to be completed and operations to commence.

Power notified the EPA and the NJDEP that it was evaluating the continued operation of the Hudson coal unit in light of changes in the energy and capacity markets, increases in the cost of pollution control equipment and other necessary modifications to the unit. On November 30, 2006, Power, reached an agreement with the EPA and NJDEP on an amendment to its 2002 agreement intended to achieve the emissions reductions targets of this agreement while providing more time to assess the feasibility of installing additional advanced emissions controls at Hudson.

The amended agreement with the EPA and the NJDEP will allow Power to continue operating Hudson and extend for four years the deadline for installing environmental controls beyond the previous December 31, 2006 deadline. Power will be required to undertake a number of technology projects (SCRs, scrubbers, baghouses, and carbon injection), plant modifications, and operating procedure changes at Hudson and Mercer designed to meet targeted reductions in emissions of NOx, SO2, particulate matter, and mercury. In addition, Power has agreed to notify the EPA and NJDEP by the end of 2007 whether it will install the additional emissions controls at Hudson by the end of 2010, or plan for the orderly shut down of the unit.

Under the program to date, Power has installed Selective Catalytic Reduction Systems (SCRs) at Mercer at a cost of approximately $113 million. The cost of implementing the balance of the amended agreement at Mercer and Hudson is estimated at $400 million to $500 million for Mercer and at $600 million to $750 million for Hudson and will be incurred in the 2007-2010 timeframe. As part of the agreement, Fossil has agreed to purchase and retire emissions allowances, contribute approximately $3 million for programs to reduce particulate emissions from diesel engines in New Jersey, and pay a $6 million civil penalty.

SO_2 / NO_x

To reduce emissions of SO2 for acid rain prevention, the CAA sets a cap on total SO2 emissions from affected units and allocates SO2 allowances (each allowance authorizes the emission of one ton of SO2) to those units. Generation units with emissions greater than their allocations can obtain allowances from sources that have excess allowances. At this time, Power does not expect to incur material expenditures to continue complying with the acid rain SO2 emissions program.

The EPA has issued regulations (commonly known as the NOx State Implementation Plan (SIP) Call) requiring 19 states in the eastern half of the U.S. and the District of Colombia to reduce and cap NOx emissions from power plant and industrial sources. The NOx reduction requirements are consistent with requirements already in place in New Jersey, New York, Connecticut and Pennsylvania, and therefore have not had an additional impact on the capacity available from Power s facilities in those states. Power has been implementing measures to reduce NOx emissions at several of its units (including the installation of selective catalytic reduction systems at the Mercer Generating Station), which has reduced the impact of any further increases to the costs of allowances.

In 1997, the EPA adopted a new air quality standard for fine particulate matter and a revised air quality standard for ozone. In 2004, the EPA identified and designated areas of the U.S. that fail to meet the revised federal health standard for ozone or the new federal health standard for fine particulates. States are expected to develop regulatory measures necessary to achieve and maintain the health standards, which may require reductions in NOx and SO2 emissions. Additional NOx and SO2 reductions also may be required to satisfy requirements of an EPA rule protecting visibility in many of the nation s Class 1 (pristine) environmental areas. Most of Power s fossil facilities would be affected by this initiative.

In May 2005, the EPA published the final Clean Air Interstate Rule (CAIR) that identifies 28 states and the District of Columbia as contributing significantly to the levels of fine particulates and/or eight-hour ozone in downwind states. New Jersey, New York, Pennsylvania, Indiana, Texas and Connecticut are among the states the EPA lists in the CAIR. Based on state obligations to address interstate transport of pollutants under the CAA, the EPA has proposed a two-phased emission reduction program for NOx and SO2, with Phase 1 beginning in 2009 (NOx) and 2010 (SO2) and Phase 2 beginning in 2015. The EPA is recommending that the program be implemented through a cap-and-trade program, although states are not required to proceed in this manner.

In December 2005, the EPA proposed new National Ambient Air Quality Standards for particulate matter.

Power is unable to determine whether any costs it may incur to comply with the above standards would be material.

Carbon Dioxide (CO_2) Emissions

Several states, primarily in the Northeastern U.S., are developing state-specific or regional legislative initiatives to stimulate CO2 emissions reductions in the electric power industry. New York initiated the Regional Greenhouse Gas Initiative (RGGI) in April 2003. Currently, in the RGGI, seven Northeastern states have signed a memorandum of understanding (MOU) intended to cap and reduce CO2 emissions from the electric power sector in the RGGI region. A final model rule was issued on August 15, 2006 that includes

MOU commitments and makes recommendations for states to move forward. The model rule contemplates the creation of a CO_2 allowance allocation and auction whereby CO_2 generators in the electric power industry would be expected to acquire through allocation, or purchase through an auction, CO_2 allowances in an amount corresponding to each facility s emissions. Facilities with an insufficient number of allowances would be required to purchase additional allowances. New York has publicly announced its intent to subject 100% of the allowances to auction, and other states, including New Jersey, may do the same. States are expected to enact legislation and/or regulation representing, at least, the minimum requirements stipulated in the MOU. The RGGI program is scheduled to start in 2009. The NJDEP in 2005 finalized amendments to its regulations governing air pollution control that would designate CO_2 as an air contaminant subject to regulation. In February 2007, the Governor of New Jersey issued an executive order committing the State to reduce emissions of greenhouse gasses 20% by 2020 and 80% by 2050. The outcome of this initiative cannot be determined at this time; however, adoption of stringent CO_2 emissions reduction requirements in the Northeast, including the allocation of allowances to PSEG s facilities and the prices of allowances available through auction, could materially impact Power s operation of its fossil fuel-fired electric generating units.

Other Air Pollutants

In March 2005, the EPA promulgated two rules: one revising its December 2000 determination that Hazardous Air Pollutants from coal-fired and oil-fired Electric Generating Units (EGUs) should be regulated under section 112 of the CAA and, on that basis, removing those units from the section 112(c) source category list (known as the delisting rule); the second establishing a New Source Performance Standard limit for nickel emissions from oil-fired EGUs, and a cap-and-trade program for mercury emissions from coal-fired EGUs, with a first phase cap of 38 tons per year (tpy) in 2010 and a second phase cap of 15 tpy in 2018 (the cap-and-trade rule). The EPA determined that it would not regulate other emissions from coal-fired and oil-fired EGUs.

A number of environmental and medical groups, the city of Baltimore and a total of 16 states (all six New England states, New Jersey, California, Delaware, Illinois, New Mexico, New York, Minnesota, Pennsylvania, Michigan and Wisconsin) have sued the EPA challenging that the rules should be more restrictive. The environmental petitioners, but not the states, also sought a stay of the rules from both the agency and the court, but the request was denied. The outcome of these litigations cannot be determined at this time.

New Jersey and Connecticut have adopted standards for the reduction of emissions of mercury from coal-fired electric generating units. The Connecticut legislation requires coal-fired power plants in Connecticut to achieve either an emissions limit or a 90% mercury removal efficiency through technology installed to control mercury emissions effective in July 2008. The regulations in New Jersey require coal-fired electric generating units in New Jersey to meet certain emission limits or reduce emissions by 90% by December 15, 2007. Companies that are parties to multi-pollutant reduction agreements are permitted to postpone such reductions on half of their coal-fired electric generating capacity until December 15, 2012. Power has a multi-pollutant reduction agreement with the NJDEP as a result of a consent decree that resolved issues arising out of the PSD and NSR air pollution control programs at the Hudson, Mercer and Bergen facilities. Substantial uncertainty exists regarding the feasibility of achieving the reductions in mercury emissions required by the New Jersey regulations and Connecticut statute; however, the estimated costs of technology believed to be capable of meeting these emissions limits at Power s coal-fired unit in Connecticut by July 2008 and at its Mercer Station by December 15, 2007 are included in Power s capital expenditure forecast.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to waters of the U.S. from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including the NJDEP, to administer the NPDES program through state acts. The New Jersey Water Pollution Control Act (NJWPCA) authorizes the NJDEP to implement regulations and to administer the NPDES program with EPA oversight, and to issue and enforce New Jersey Pollutant Discharge Elimination System (NJPDES) permits. Power and Energy Holdings also have ownership interests in domestic facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern Power s or Energy Holdings facilities in these jurisdictions.

The EPA promulgated regulations under FWPCA Section 316(b), which requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Phase I of the rule covering new facilities became effective on January 17, 2002. None of the projects that Power currently has under construction or in development is subject to the Phase I rule. The Phase II rule covering large existing power plants became effective on September 7, 2004. The Phase II regulations provided five alternative methods by which a facility can demonstrate that it complies with the requirement for BTA for minimizing adverse environmental impacts associated with cooling water intake structures.

On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued its decision in litigation of the Phase II rule brought by several environmental groups, the Attorneys General of six Northeastern states, the Utility Water Act Group and several of its members, including Power. The court remanded major portions of the rule and determined that Section 316(b) of the Clean Water Act does not support the use of restoration and the site specific cost-benefit test. Among the provisions the court remanded back to EPA for further consideration and rulemaking, the court instructed EPA to reconsider the definition of BTA without comparing the costs of the best performing technology to its benefits. Prior to this decision, Power has used restoration and site-specific cost benefit tests in applications it has filed to renew the NJPDES permits at its once-though cooled plants, including Salem, Hudson and Mercer. Although the rule applies to all of Power s electric generating units that use surface waters for once-through cooling purposes, the impact of the rule and the decision of the court cannot be determined at this time for all of Power s facilities. Depending on the outcome of any appeals, or actions by EPA to repromulgate the rule, this decision could have a material impact on Power s ability to renew its NPDES permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, New Haven and Bridgeport, without making significant upgrades to their existing intake structures and cooling systems. The costs of those upgrades could be material to one or more of Power s once-through cooled plants.

Power

Permit Renewals

For information on permit renewals for Salem, see Note 12, Commitments and Contingent Liabilities of the Notes.

PSE&G and Power

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and New Jersey Spill Compensation and Control Act (Spill Act)

CERCLA and the Spill Act authorize Federal and state trustees for natural resources to assess damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. In 2003, the NJDEP issued a policy directive memorializing its efforts to recover natural resource damages and its intent to continue to pursue the recovery of natural resource damages. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. PSE&G and Power cannot assess the magnitude of the potential financial impact of this regulatory change. See Note 12. Commitments and Contingent Liabilities of the Notes for additional information.

Because of the nature of PSE&G s and Power s respective businesses, including the production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, various by- products and substances are or were produced or handled that contain constituents classified by Federal and state authorities as hazardous. For discussions of these hazardous substance issues and a discussion of potential liability for remedial action regarding the Passaic River, see Note 12. Commitments and Contingent

Liabilities of the Notes. For a discussion of remediation/clean-up actions involving PSE&G and Power, see Item 3. Legal Proceedings.

Uranium Enrichment Decontamination and Decommissioning Fund

In accordance with the EP Act, domestic entities that own nuclear generating stations are required to pay into a decontamination and decommissioning fund, based on their past purchases of U.S. government enrichment services. Since these amounts are being collected from PSE&G s customers over a period of 15 years, this obligation remained with PSE&G following the generation asset transfer to Power in 2000. PSE&G s obligation for the nuclear generating stations in which it had an interest was $76 million (adjusted for inflation). As of December 31, 2006, PSE&G and Power had both paid their remaining obligations.

New Jersey Operating Permits

The New Jersey Air Pollution Control Act requires that certain sources of air emissions obtain operating permits issued by NJDEP. All of Power s generating facilities in New Jersey are required to have such operating permits. The costs of compliance associated with any new requirements that may be imposed by these permits in the future are not known at this time and are not included in capital expenditures, but may be material.

Power

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, as amended (NWPA), the Federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund at a rate of one mil ($0.001) per kWh of nuclear generation, subject to such escalation as may be required to assure full cost recovery by the Federal government. Under the NWPA, the U.S. Department of Energy (DOE) was required to begin taking possession of the spent nuclear fuel by no later than 1998. The DOE has announced that it does not expect a facility for such purpose to be available earlier than 2017.

Pursuant to NRC rules, spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in independent spent fuel storage installations located at reactors or away-from- reactor sites for at least 30 years beyond the licensed life for reactor operation (which may include the term of a revised or renewed license). Adequate spent fuel storage capacity is estimated to be available through 2011 for Salem 1 and 2015 for Salem 2. Power completed, in August 2006, construction of an on-site storage facility that will satisfy the spent fuel storage needs of Hope Creek through the end of its current license. Exelon Generation has advised Power that it has a licensed and operational on-site storage facility at Peach Bottom that will satisfy Peach Bottom s spent fuel storage requirements until at least 2014.

Exelon Generation had previously advised Power that it had signed an agreement with the DOE, applicable to Peach Bottom, under which Exelon Generation would be reimbursed for costs incurred resulting from the DOE s delay in accepting spent nuclear fuel for permanent storage. Future costs incurred resulting from the DOE delays in accepting spent fuel will be reimbursed annually until the DOE fulfills its obligation to accept spent nuclear fuel. In addition, Exelon Generation and Nuclear are required to reimburse the DOE for the previously received credits from the Nuclear Waste Fund, plus lost earnings. Under this settlement, Power received approximately $27 million for its share of previously incurred storage costs for Peach Bottom, $22 million of which was used for the required reimbursement to the Nuclear Waste Fund. Exelon Generation paid Power approximately $5.4 million for its portion of the spent fuel storage costs reimbursed by the DOE in 2005 for costs incurred between October 1, 2003 and June 30, 2005.

In September 2001, Power filed a complaint in the U.S. Court of Federal Claims seeking damages for Salem and Hope Creek caused by the DOE not taking possession of spent nuclear fuel in 1998. On October 14, 2004, an order to show cause was issued regarding whether the U.S. Court of Federal Claims has jurisdiction over the matter. Power responded to this order in November 2004. On January 31, 2005, the Court dismissed the breach-of-contract claims of Power and three other utilities. Power moved for reconsideration in the U.S. Court of Federal Claims and jointly petitioned for permission to appeal the January 31, 2005 order to the U.S. Court of Appeals for the Federal Circuit. On September 29, 2006, the U.S. Court of Appeals for the Federal Circuit reversed the adverse U.S. Court of Federal Claims jurisdictional ruling and reinstated Power s claims in the U.S. Court of Federal Claims. No assurances can be given as to any damage recovery or the ultimate availability of a disposal facility.

Spent Fuel Pool

The spent fuel pool at each Salem unit has an installed leakage collection system. This system was found to be obstructed at Salem Unit 1. Power developed a solution to maintain the design function of the leakage collection system at Salem Unit 1 and investigated the existence of any structural degradation that might have been caused by the obstruction. The concrete and reinforcing steel laboratory tests results were completed in March 2006. Test results that have been collected as part of the ongoing testing indicate that no repairs are anticipated. The NRC issued Information Notice 2004-05 in March 2004 concerning this emerging industry issue and Power cannot predict what further actions the NRC may take on this matter.

Elevated concentrations of tritium in the shallow groundwater at Salem Unit 1 were detected in early 2003. This information was reported to the NJDEP and the NRC, as required. Power conducted a comprehensive investigation in accordance with NJDEP site remediation regulations to determine the source and extent of the tritium in the groundwater. Power is conducting remedial actions to address the contamination in accordance with a remedial action workplan approved by the NJDEP in November 2004. The remedial actions are expected to be ongoing for several years. The costs necessary to address this on-site groundwater contamination issue are not expected to be material.

Low Level Radioactive Waste (LLRW)

As a by-product of their operations, nuclear generation units produce LLRW. Such wastes include paper, plastics, protective clothing, water purification materials and other materials. LLRW materials are accumulated on-site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators, including Power, continued access to the Barnwell LLRW disposal facility which is owned by South Carolina. Power believes that the Atlantic Compact will provide for adequate LLRW disposal for Salem and Hope Creek through the end of their current licenses, although no assurances can be given. Both Power and Exelon have on-site LLRW storage facilities for Salem, Hope Creek and Peach Bottom, which have the capacity for at least five years of temporary storage for each facility. For information regarding Nuclear Spent Fuel Pool, see Note 12. Commitments and Contingent Liabilities of the Notes.

PSE&G

MGP Remediation Program

For information regarding PSE&G s MGP Remediation Program, see Note 12. Commitments and Contingent Liabilities of the Notes.

ITEM 1A. RISK FACTORS

PSEG, PSE&G, Power and Energy Holdings

The following factors should be considered when reviewing the businesses of PSEG, PSE&G, Power and Energy Holdings. These factors could significantly impact the businesses and cause results to differ materially from those expressed in any statements made by, or on behalf of PSEG, PSE&G, Power or Energy Holdings herein. Some or all of these factors may apply to each of PSEG, PSE&G, Power, Energy Holdings and their respective subsidiaries.

Generation operating performance may fall below projected levels

Power and Energy Holdings

Operating generating stations below expected capacity levels, especially at low-cost nuclear and coal facilities, may result in lost revenues and increased expenses, including replacement power costs. Factors that could cause generating station operations to fall below expected levels include, but are not limited to, the following:

- breakdown or failure of equipment, processes or management effectiveness;
- disruptions in the transmission of electricity;

- labor disputes;
- fuel supply interruptions or transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements;
- permit limitations; and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, acts of terrorism or other similar occurrences.

The potential lost revenues and increased expenses could result in a case where sufficient cash may not be available to service debt. In addition, any prolonged operating performance issues could potentially result in an impairment of the value of the affected facility.

Failure to obtain adequate and timely rate relief could negatively impact results

PSE&G

As a public utility, PSE&G s rates are regulated. These rates are designed to allow PSE&G the opportunity to recover its operating expenses and earn a fair return on its rate base, which primarily consists of its property, plant and equipment. These rates include its electric and gas tariff rates that are subject to regulation by the BPU as well as its transmission rates that are subject to regulation by FERC. PSE&G s base rates are set by the BPU for electric distribution and gas distribution and are effective until the time a new rate case is brought to the BPU. These base rate cases generally take place when equity returns fall below reasonable levels. Some categories of costs, such as energy costs, are recovered through adjustment charges that are periodically reset to reflect actual costs. If these costs exceed the amount included in PSE&G s adjustment charges, there may be a negative impact on cash flows.

If PSE&G does not obtain adequate rate treatment on a timely basis in order to meet its operating expenses, there may be a negative impact on earnings and operating cash flows. PSE&G can give no assurances that tariff relief will be timely or sufficient for it to recover its costs and provide a sufficient return for its investors.

Energy Holdings

Global s distribution facilities are rate-regulated enterprises. Governmental authorities establish rates charged to customers. While these rates are designed to cover all operating costs and provide a return on investment, Energy Holdings can give no assurances that rates will, in the future, be sufficient to cover Global s costs and provide a sufficient return on its investments. In addition, future rates may not be adequate to provide cash flow to pay principal and interest on the debt of Global s subsidiaries and affiliates or to enable its subsidiaries and affiliates to comply with the terms of debt agreements.

Inability to balance energy obligations, available supply and trading risks could negatively impact results

Power and Energy Holdings

The revenues generated by the operation of the generating stations are subject to market risks that are beyond each company s control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into other competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments through recovery of mandated rates payable by purchasers of electricity.

Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Power

Power s energy trading and marketing activities frequently involve the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that Power has produced or purchased energy in excess of its contracted obligations a reduction in market prices could reduce profitability.

Conversely, to the extent that Power has contracted obligations in excess of energy it has produced or purchased, an increase in market prices could reduce profitability.

If the strategy Power utilizes to hedge its exposures to these various risks is not effective, it could incur significant losses. Power s substantial market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances and pricing differentials at various geographic locations, which cannot be predicted with any certainty.

Increases in market prices also affect Power s ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices and, resultingly, could require the maintenance of liquidity resources that would be prohibitively expensive.

Environmental regulations could limit operations

PSEG, PSE&G, Power and Energy Holdings

PSEG, PSE&G, Power and Energy Holdings are required to comply with numerous statutes, regulations and ordinances relating to the safety and health of employees and the public, the protection of the environment and land use. These statutes, regulations and ordinances are constantly changing. While management believes that PSEG, PSE&G, Power and Energy Holdings have obtained all material approvals currently required to own and operate their respective facilities and that approvals will be issued in a timely manner, significant additional costs could be incurred in order to comply with these requirements. In some cases, the cost of compliance could exceed the marginal value of the facility. Failure to comply with environmental statutes, regulations and ordinances could have a material effect on PSEG, PSE&G, Power and Energy Holdings, including potential civil or criminal liability, the imposition of clean-up liens or fines and expenditures of funds to bring facilities into compliance or possible impairment of the value of the affected facility.

PSEG, PSE&G, Power and Energy Holdings can give no assurance that they will be able to:

obtain all required environmental approvals not yet received or that may be required in the future;

obtain any necessary modifications to existing environmental approvals;

maintain compliance with all applicable

environmental laws, regulations and approvals; or

recover any resulting costs through future sales.

Delay in obtaining or failure to obtain and maintain in full force and effect any environmental approvals, or delay or failure to satisfy any applicable environmental regulatory requirements, could prevent construction of new facilities, operation of existing facilities or sale of energy from these facilities or could result in significant additional costs.

Power

Many of Power s generating facilities are located in the State of New Jersey where environmental programs are generally considered to be more stringent in comparison to similar programs in other states. As such, there may be instances where the facilities located in New Jersey are subject to more stringent and, therefore, more costly pollution control requirements than competitive facilities in other states.

Regulatory issues significantly impact operations and profitability

PSEG, PSE&G, Power and Energy Holdings

Federal, state and local authorities impose substantial regulation and permitting requirements on the electric power generation business. Power and Energy Holdings are required to comply with numerous laws and regulations and to obtain numerous governmental permits in order to operate generation stations. In addition, PSE&G s and certain of Global s distribution facilities could be subject to financial penalties if reliability performance standards are not met.

PSEG, PSE&G, Power and Energy Holdings can give no assurance that existing regulations will not be revised or reinterpreted, that new laws and regulations will not be adopted or become applicable or that future changes in laws and regulations, including the possibility of reregulation in some deregulated markets, will not have a detrimental effect on their respective businesses.

Power and Energy Holdings

Power and Energy Holdings believe that they have obtained all material energy-related federal, state and local approvals currently required to operate their respective generation stations and sell energy output, including MBR authority from FERC. Although not currently required, additional regulatory approvals may be required in the future due to changes in laws and regulations or for other reasons. No assurance can be given that Power and Energy Holdings will be able to obtain any required regulatory approval in the future, or that they will be able to obtain any necessary extensions in receiving any required regulatory approvals.

Power is also subject to pervasive regulation by the NRC with respect to the operation of nuclear generation stations. This regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety, environmental and personnel management requirements. The NRC also requires continuous demonstrations that plant operations meet applicable requirements. The NRC has the ultimate authority to determine whether any nuclear generation unit may operate.

Any failure to obtain or comply with any required regulatory approvals could materially adversely affect Power s and Energy Holdings ability to operate generation stations or sell electricity to third parties.

In addition, there is also a risk to Power and Energy Holdings if states decide to turn away from competition and allow regulated utilities to continue to own or reacquire and operate generating stations in a regulated and potentially uneconomical manner, or to encourage rate-based treatment for the construction of new base-load generating units. This has already occurred in certain states. The lack of consistent rules in markets outside of PJM can negatively impact the competitiveness of Power s plants.

Moreover, current rules being developed at FERC, at DOE and at PJM with respect to the access to and construction of transmission and the allocation of costs for such construction may have the effect of altering the level playing field between transmission options and generation options, which could have a competitive impact upon PSEG and Power.

Availability of adequate power transmission facilities

PSEG, PSE&G, Power and Energy Holdings

The ability to sell and deliver electric energy products may be adversely impacted and the ability to generate revenues may be limited if:

- transmission is disrupted;
- transmission capacity is inadequate; or
- a region s power transmission infrastructure is inadequate.

Inability to access sufficient capital in the amounts and at the times needed

PSEG, PSE&G, Power and Energy Holdings

Capital for projects and investments has been provided by internally-generated cash flow, equity issuances by PSEG and borrowings by PSEG, PSE&G, Power, Energy Holdings and their respective subsidiaries. Continued access to debt capital from outside sources is required in order to efficiently fund the cash flow needs of the businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to access sufficient capital in the bank and debt capital markets is dependent upon current and future capital structure, performance, financial condition and the availability of capital at a reasonable economic cost. As a result, no assurance can be given that PSEG, PSE&G, Power or Energy Holdings will be successful in obtaining financing for projects and investments or funding the equity commitments required for such projects and investments in the future.

Counterparty credit risks or a deterioration of credit quality

PSEG, PSE&G, Power and Energy Holdings

As market prices for energy and fuel fluctuate, Power s forward energy sale and forward fuel purchase contracts could require substantial collateral requiring Power to source additional liquidity during periods when Power s ability to source such liquidity may be limited. Also, in connection with its energy trading activities, Power must meet credit quality standards required by counterparties. Standard industry contracts generally require trading counterparties to maintain investment grade ratings. These same contracts provide reciprocal benefits to Power. If Power loses its investment grade credit rating, ER&T would have to provide additional collateral in the form of letters of credit or cash, which would significantly impact the energy trading business. This would increase Power s costs of doing business and limit its ability to successfully conduct energy trading operations.

Power sells generation output through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual obligations. Any failure to perform on the part of these counterparties could have a material impact on PSEG s and Power s results of operations, cash flows and financial position. As market prices rise above contracted price levels, Power is required to post collateral with purchasers. Collateral posting requirements for BGS contracts in particular are one-sided. If market prices fall below BGS contracted price levels for a single contract, power purchasers are not required to post collateral with Power. However, such margin positions can be netted against margin due from Power in other BGS contracts with the same counterparty.

Substantial competition from well-capitalized participants in the worldwide energy markets

PSEG, PSE&G, Power and Energy Holdings

Restructuring of worldwide energy markets is creating opportunities for, and substantial competition from, well-capitalized entities that may adversely affect the ability of PSEG, PSE&G, Power and Energy Holdings to make investments on favorable terms and achieve growth objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower returns which may affect PSEG s, PSE&G s, Power s and Energy Holdings ability to service their respective outstanding indebtedness, including short-term debt. Some of the competitors include:

- merchant generators;
- banks, funds and other financial entities;
- domestic and multi-national utility generators;
- energy marketers;
- fuel supply companies; and
- affiliates of other industrial companies.

As a holding company, the ability to service debt could be limited

PSEG and Energy Holdings

PSEG and Energy Holdings are holding companies with no material assets other than the stock or membership interests of their subsidiaries and project affiliates. As such, PSEG and Energy Holdings depend on their respective subsidiaries and project affiliates cash flow and their respective access to capital in order to service their indebtedness. Each of PSEG s and Energy Holdings respective subsidiaries and project affiliates are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay any amounts when due on PSEG s or Energy Holdings debt or to make any funds available to pay such amounts. As a result, PSEG s and Energy Holdings debt will effectively be subordinated to all existing and future debt, trade creditors, and other liabilities of their respective subsidiaries and project affiliates and PSEG s and Energy Holdings rights and hence the rights of their respective creditors to participate in any distribution of assets of any subsidiary or project affiliate upon its liquidation or reorganization or otherwise would be subject to the prior claims of that subsidiary s or project affiliate s creditors, except to the extent that PSEG s or Energy Holdings claims as a creditor of such subsidiary or project affiliate may be recognized.

In addition, Energy Holdings subsidiaries project-related debt agreements generally restrict the subsidiaries ability to pay dividends, make cash distributions or otherwise transfer funds. These restrictions may include achieving and maintaining financial performance or debt coverage ratios, absence of events of default, or priority in payment of other current or prospective obligations. Also, Energy Holdings is structurally designed to be able to meet its obligations without any support from its parent, PSEG. These restrictions could further restrict Energy Holdings ability to service its outstanding indebtedness.

Adverse international developments could negatively impact results

Energy Holdings

A component of PSEG s and Energy Holdings business is international distribution and generation, primarily in Chile and Peru. The economic and political conditions in certain countries where Global has interests present risks that may be different than those found in the U.S. which could affect the value of its investments, cash flows from projects and make it more difficult to obtain non-recourse project refinancing on suitable terms or could impair Global s ability to enforce its rights under agreements relating to such projects. Such risks include:

- expropriation or nationalization of energy assets;
- renegotiation or abrogation of existing contracts; and
- changes in law or tax policy.

Operations in foreign countries also present risks associated with currency exchange rates and convertibility, inflation and repatriation of earnings. In some countries, economic and monetary conditions and other factors could affect Global s ability to convert its cash distributions to U.S. Dollars or other freely convertible currencies, or to move funds offshore from these countries. Furthermore, the central bank of any of these countries may have the authority to suspend, restrict or otherwise impose conditions on foreign exchange transactions or to approve distributions to foreign investors.

Inability to realize tax benefits

Energy Holdings

Through its leveraged lease investments, Resources acquired an asset by investing equity representing approximately 15% to 20% of the cost of the asset and incurring non-recourse lease debt for the balance. As the owner, Resources is entitled to depreciate the asset under applicable federal and state tax guidelines and receives income from the tax benefits associated with interest and depreciation deductions with respect to the leased property. The ability of Resources to realize these tax benefits is dependent on operating income generated by its affiliates and allocated pursuant to PSEG s consolidated tax sharing agreement. A reduction of operating income could impair Resources ability to receive such benefits, which would result in a reduction of earnings and cash flows. In addition, during 2006, the IRS disallowed certain deductions associated with some of the leveraged leases which have been designated by the IRS as listed transactions. For additional information see Note 12. Commitments and Contingent Liabilities of the Notes. Any material disallowance of deductions could impact Energy Holdings earnings and ability to service its outstanding indebtedness.

Decreases in the value of the pension and other postretirement assets could require additional funding

PSEG, PSE&G, Power and Energy Holdings

Adverse changes in the rates of return or performance of the investments in which the pension and other postretirement trust assets are held could lower the value of the funds and the trust assets. Such a decline in value could result in additional funding obligations to meet the applicable legal and regulatory requirements. To the extent that these additional funding obligations are significant, this could impact PSEG s, PSE&G s, Power s and Energy Holdings ability to service debt.

Changes in technology may make power generation assets less competitive

Power and Energy Holdings

A key element of the business plan is that generating power at central power plants produces electricity at relatively low cost. There are alternative technologies to produce electricity that continue to attract capital for research and development, most notably fuel cells, microturbines, windmills and photovoltaic (solar) cells. It is possible that advances in technology will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. If this were to happen, Power s and Energy Holdings market share could be eroded and the value of their respective power plants could be significantly impaired. Changes in technology could also alter the channels through which retail electric customers buy electricity, which could affect financial results.

Insurance coverages may not be sufficient

PSEG, PSE&G, Power and Energy Holdings

PSEG, PSE&G, Power and Energy Holdings have insurance for their respective facilities, including:

- all-risk property damage insurance;
- commercial general public liability insurance;
- boiler and machinery coverage;
- nuclear liability; and
- for nuclear generating units, replacement power and business interruption insurance in amounts and with deductibles that management considers appropriate.

PSEG, PSE&G, Power and Energy Holdings can give no assurance that this insurance coverage will be available in the future on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of their respective facilities will be sufficient to fund future payments on debt. Additionally, some properties may not be insured in the event of an act of terrorism.

Recession, acts of war or terrorism

PSEG, PSE&G, Power and Energy Holdings

The consequences of a prolonged recession and adverse market conditions may include the continued uncertainty of energy prices and the capital and commodity markets. Management cannot predict the impact of any continued economic slowdown, reduced growth rate in energy usage or fluctuating energy prices; however, such impact could have a material adverse effect on PSEG s, PSE&G s, Power s and Energy Holdings financial condition, results of operations and net cash flows.

Major industrial facilities, generation plants, fuel storage facilities and transmission and distribution facilities may be targets of terrorist activities that could result in disruption of PSE&G s, Power s or Energy Holdings ability to produce or distribute some portion of their respective energy products. Any such disruption could result in a significant decrease in revenues and/or significant additional costs to repair, which could have a material adverse impact on the financial condition, results of operation and net cash flows of PSEG, PSE&G, Power and Energy Holdings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG

None.

PSE&G, Power and Energy Holdings

Not Applicable.

ITEM 2. PROPERTIES

PSEG and Services

PSEG does not own any property. All property is owned by PSEG s subsidiaries.

Services leases a 25-story office tower for PSEG s corporate headquarters at 80 Park Plaza, Newark, New Jersey, together with an adjoining three-story building. In addition, Services owns the Maplewood Test Services Facility in Maplewood, New Jersey.

PSEG believes that it and its subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost.

PSE&G

PSE&G s First and Refunding Mortgage (Mortgage), securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G s property.

PSE&G s electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. These easements and other rights are deemed by PSE&G to be adequate for the purposes for which they are being used.

PSE&G believes that it maintains adequate insurance coverage against loss or damage to its principal properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost.

Electric Transmission and Distribution Properties

As of December 31, 2006, PSE&G s transmission and distribution system included approximately 21,745 circuit miles, of which approximately 7,710 circuit miles were underground, and approximately 804,936 poles, of which approximately 538,811 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2006, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

Gas Distribution Properties

As of December 31, 2006, the daily gas capacity of PSE&G s 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,973,000 therms (approximately 2,886,000 cubic feet on an equivalent basis of 1.030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	773,000
Camden LPG	Camden, NJ	280,000

Central LPG	Edison Twp., NJ	960,000
Harrison LPG	Harrison, NJ	960,000
Total		2,973,000

As of December 31, 2006, PSE&G owned and operated approximately 17,556 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, all in three operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering or regulating stations, all located in New Jersey, of which 28 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

Office Buildings and Facilities

PSE&G rents office space from Services as its headquarters in Newark, New Jersey. PSE&G also leases office space at various locations throughout New Jersey for district offices and offices for various corporate groups and services. PSE&G also owns various other sites for training, testing, parking, records storage, research, repair and maintenance, warehouse facilities and for other purposes related to its business.

In addition to the facilities discussed above, as of December 31, 2006, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 22,809 megavolt-amperes and 244 substations with an aggregate installed capacity of 7,790 megavolt-amperes. In addition, four substations in New Jersey having an aggregate installed capacity of 109 megavolt-amperes were operated on leased property.

Power

Power rents office space from Services as its headquarters in Newark, New Jersey. Other leased properties include office, warehouse, classroom and storage space, primarily located in New Jersey. Power also owns the Central Maintenance Shop at Sewaren, New Jersey.

Power has a 57.41% ownership interest in approximately 13,000 acres in the Delaware River Estuary region to satisfy the condition of the NJPDES permit issued for Salem. Power also owns several other facilities, including the on-site Nuclear Administration and Processing Center buildings.

Power has a 13.91% ownership interest in the 650-acre Merrill Creek Reservoir in Warren County, New Jersey and approximately 2,158 acres of land surrounding the reservoir. The reservoir was constructed to store water for release to the Delaware River during periods of low flow. Merrill Creek is jointly-owned by seven companies that have generation facilities along the Delaware River or its tributaries and use the river water in their operations.

Power believes that it maintains adequate insurance coverage against loss or damage to its plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Note 12. Commitments and Contingent Liabilities of the Notes.

As of December 31, 2006, Power s share of installed generating capacity was 14,639 MW, as shown in the following table:

OPERATING POWER PLANTS

Name	Location	Total Capacity (MV)	% Owned	Owned Capacity (MV)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	991	100 %	991	Coal/Gas	Load Following
Mercer	NJ	648	100 %	648	Coal/Gas	Load Following
Sewaren	NJ	453	100 %	453	Gas/Oil	Load Following
Keystone(A)(B)	PA	1,700	23 %	388	Coal	Base Load
Conemaugh(A)(B)	PA	1,700	23 %	382	Coal	Base Load
Bridgeport Harbor	CT	518	100 %	518	Coal/Oil	Base Load
New Haven Harbor	CT	455	100 %	455	Oil/Gas	Load Following
Total Steam		6,465		3,835		
Nuclear:						
Hope Creek	NJ	1,061	100 %	1,061	Nuclear	Base Load
Salem 1 & 2(A)	NJ	2,304	57 %	1,323	Nuclear	Base Load
Peach Bottom 2 & 3(A)(C)	PA	2,224	50 %	1,112	Nuclear	Base Load
Total Nuclear		5,589		3,496		
Combined Cycle:						
Bergen	NJ	1,225	100 %	1,225	Gas/Oil	Load Following
Linden	NJ	1,186	100 %	1,186	Gas	Load Following
Lawrenceburg(F)	IN	1,080	100 %	1,080	Gas	Load Following
Bethlehem	NY	793	100 %	793	Gas	Load Following
Total Combined Cycle		4,284		4,284		

Combustion Turbine:						
Essex	NJ	617	100 %	617	Gas/Oil	Peaking
Edison	NJ	504	100 %	504	Gas/Oil	Peaking
Kearny	NJ	443	100 %	443	Gas/Oil	Peaking
Burlington	NJ	557	100 %	557	Gas/Oil	Peaking
Linden	NJ	340	100 %	340	Gas/Oil	Peaking
Mercer	NJ	129	100 %	129	Oil	Peaking
Sewaren	NJ	129	100 %	129	Oil	Peaking
Bergen	NJ	21	100 %	21	Gas	Peaking
National Park	NJ	21	100 %	21	Oil	Peaking
Kearny	NJ	21	100 %	21	Gas	Peaking
Salem(A)	NJ	38	57 %	22	Oil	Peaking
Bridgeport Harbor	CT	15	100 %	15	Oil	Peaking
Total Combustion Turbine		2,835		2,819		
Internal Combustion:						
Conemaugh(A)(B)	PA	11	23 %	2	Oil	Peaking
Keystone(A)(B)	PA	11	23 %	3	Oil	Peaking
Total Internal Combustion		22		5		
Pumped Storage:						
Yards Creek(A)(D)(E)	NJ	400	50 %	200	Peaking	
Total Operating Generation Plants		19,595		14,639		

(A) Power s share of jointly-owned facility.

(B) Operated by Reliant Energy.

(C) Operated by Exelon

Generation.

(D) Operated by JCP&L.

(E) Excludes energy for pumping and synchronous condensers.

(F) On December 29, 2006, Power entered into an agreement to sell Lawrenceburg. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

As of December 31, 2006, Power had generating capacity in construction or advanced development, as shown in the following table:

POWER PLANTS IN ADVANCED DEVELOPMENT

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Scheduled In Service Date
Nuclear Uprates	NJ/PA	160	Various	142	Nuclear	2007-2008
Total Advanced Development.		160		142		

Projected Capacity	Total Owned Capacity (MW)
Total Owned Operating Generation Plants	14,639
Advanced Development	142
Less: Planned Sales	(1,080)
Projected Capacity	13,701

Energy Holdings

Energy Holdings rents office space from Services as its headquarters in Newark, New Jersey.

Energy Holdings believes that it maintains adequate insurance coverage for properties in which its subsidiaries have an equity interest, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost.

Global has invested in the following generation facilities that were in operation as of December 31, 2006:

OPERATING POWER PLANTS

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
United States(A)					
Texas Independent Energy, L.P. (TIE) Guadalupe Power Partners, LP (Guadalupe)	TX	1,000	100 %	1,000	Natural gas
Odessa-Ector Power Partners, L.P. (Odessa)	TX	1,000	100 %	1,000	Natural gas
Total TIE		2,000		2,000	
Kalaeloa Partners L.P. (Kalaeloa)	HI	208	50 %	104	Oil
GWF Power Systems, L.P. (GWF)	CA	105	50 %	53	Petroleum coke
Hanford L.P. (Hanford)	CA	27	50 %	13	Petroleum coke
GWF Energy LLC (GWF Energy)					
Hanford Peaker Plant	CA	95	60 %	57	Natural gas
Henrietta Peaker Plant	CA	97	60 %	58	Natural gas
Tracy Peaker Plant	CA	171	60 %	103	Natural gas
Total GWF Energy		363		218	
Bridgewater	NH	16	40 %	6	Biomass
Conemaugh	PA	15	4 %	1	Hydro
Total United States		2,734		2,395	
International					
PPN Power Generating Company Limited (PPN)	India	330	20 %	66	Naphtha/Natural gas
Prisma					
Crotone	Italy	20	43 %	9	Biomass
Bando D Argenta I	Italy	20	85 %	17	Biomass
Strongoli	Italy	40	43 %	17	Biomass
Total Prisma		80		43	

Electroandes	Peru	180	100 %	180	Hydro
Turboven					
Maracay	Venezuela	60	50 %	30	Natural gas
Cagua	Venezuela	60	50 %	30	Natural gas
Total Turboven		120		60	
Turbogeneradores de Maracay (TGM)	Venezuela	40	9 %	4	Natural gas
SAESA Group	Chile	120	100 %	120	Natural gas/ Gas/Oil/Hydro/Wind
Total International		870		473	
Total Operating Power Plants		3,604		2,868	

(A) On December 22, 2006, Global entered into an agreement to sell its 34.5% interest in Thermal Energy Development Partnership, L.P. which owns the 21 MW biomass-fueled Tracy project in California and therefore, has been excluded. The sale closed in January 2007. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

Domestic Generation

TIE

Global owns 100% of TIE which owns and operates two electric generation facilities, one in Guadalupe County in south central Texas (Guadalupe) and one in Odessa in western Texas (Odessa). Approximately 30% of the total expected output of TIE for 2007 has been sold via bilateral agreements and additional bilateral sales for peak and off-peak services will be signed as the year progresses. Any remaining uncommitted output is sold in the Texas spot market. Included in the amounts above is a 350 MW daily capacity call option at Odessa that expires on December 31, 2010.

Kalaeloa

Global s 50% partner in Kalaeloa is a power fund managed by Harbert Power Corporation (Harbert). All of the electricity generated by the Kalaeloa power plant is sold to the Hawaiian Electric Company, Inc. (HECO) under a PPA expiring in May 2016. Under a steam purchase and sale agreement expiring in May 2016, the Kalaeloa power plant supplies steam to the adjacent Tesoro refinery. The primary fuel, low sulfur fuel oil, is provided from the adjacent Tesoro refinery under a long-term all requirements contract. The refinery is interconnected to the power plant by a pipeline and preconditions the fuel oil prior to delivery. Back-up fuel supply is provided by HECO.

The two combustion turbines of Kalaeloa were upgraded in 2004 resulting in both an increase in the net plant output by approximately 20 MW and an improvement in the efficiency of consuming fuel. As a result of the upgrades, Kalaeloa and HECO entered into two amendments to the PPA. The amendments were effective upon final approval from the Public Utility Commission of the State of Hawaii in September 2005. The amendments increased Kalaeloa s firm capacity and associated energy sales to HECO from 180 MW to 208 MW.

GWF and Hanford

Global and an affiliate of Harbert each own 50% of GWF. PPAs for the five GWF Bay Area plants net output are in place with Pacific Gas and Electric Company (PG&E) ending in 2020 and 2021. GWF acquires the petroleum coke used to fuel its plants through contracts with three local oil refineries with minimum volumes nominated by GWF annually and price negotiated between the parties either semi-annually or annually. Three of the five GWF plants have been modified to burn a wider variety of petroleum coke products to mitigate fuel supply and pricing risk.

Global and an affiliate of Harbert each own 50% of Hanford. A PPA for the plant s net output is in place with PG&E ending in August 2011. Hanford acquires the petroleum coke fired in its plant through a contract with a refinery with price negotiated semi-annually.

Hanford, Henrietta and Tracy Peaker Plants

GWF Energy, which is 60% owned by Global and 40% owned by a power fund managed by Harbert, owns and operates three peaker plants in California. Global owned approximately 75% of GWF Energy until February 2004 when it sold a 14.9% interest to Harbinger for approximately $14 million. The output of these plants is sold under a PPA with the California Department of Water Resources (DWR) with maturities in 2011 and 2012. DWR has the right to schedule energy and/or reserve capacity from each unit of the three plants for a maximum of 2,000 hours each year. Energy and capacity not scheduled by DWR is available for sale by GWF Energy. DWR supplies the natural gas when the units are scheduled for dispatch by DWR. GWF Energy obtains the natural gas used to fuel its plants for non-DWR sales from the spot market on a non-firm basis.

International Generation

India

PPN

Global owns a 20% interest in PPN located in Tamil Nadu, India. Global s partners include the Apollo Infrastructure Company Ltd., with a 46.9% interest, Marubeni Corporation, with a 26% interest, Housing

Development Finance Corporation (HDFC) and HDFC Life Insurance Corporation, with a 5% and 2.1% interest respectively. PPN has entered into a PPA for the sale of 100% of its output to the State Electricity Board of Tamil Nadu (TNEB) for 30 years, with an agreement to take-or-pay equal to a plant load factor of at least 68.5%.

Italy

Prisma

Global owns an 85% interest in Prisma which indirectly owns and operates three biomass generation plants in Italy through its ownership of 100% of San Marco Bioenergie S.p.A., which owns a 20 MW plant, and 50% of Biomasse, a partnership with Api Holding S.p.A., which owns two plants totaling 60 MW. Global records Prisma s investment in Biomasse as an equity method investment due to Global s approximate 43% indirect ownership in Biomasse. The output of the plants is sold under power purchase agreements with the Italian national grid (CIP contracts), which include a premium for the renewable energy output. These contracts expire from 2009 through 2012. For additional information relating to Prisma, see Note 12. Commitments and Contingent Liabilities of the Notes.

Peru

Electroandes

Global owns a 100% interest in Electroandes located in Peru. Electroandes main assets include four hydroelectric facilities with a combined installed capacity of 180 MW and 437 miles of transmission lines located in the central Andean region east of Lima. Electroandes revenues were obtained through various PPAs, denominated in U.S. Dollars. Electroandes has contracted for 95% and 91% in 2007 and 2008, respectively, and over 50% for 2009 and 2010. Approximately 75% of the PPAs in 2007 are with unregulated customers with a more balanced split between regulated and unregulated in 2008 and beyond.

Venezuela

Turboven

The facilities in Maracay and Cagua are owned and operated by Turboven, an entity which is jointly-owned by Global (50%) and Corporacion Industrial de Energia (CIE). PPAs expiring between 2007 and 2011 have been entered into for the sale of approximately 40% of the output of Maracay and Cagua to various industrial customers. The PPAs are structured to provide energy only with minimum take provisions. Fuel costs are passed through directly to customers and the energy tariffs are calculated in U.S. Dollars and paid in local currency. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes for a discussion of recent events in Venezuela.

TGM

Global has a 9% indirect interest in TGM through a partnership with CIE. TGM sells all of the energy produced under a PPA with Manufacturas del Papel (MANPA), a paper manufacturing concern located in Maracay. MANPA and CIE have common controlling shareholders. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes for a discussion of recent events in Venezuela.

Electric Distribution Facilities

Global has invested in the following major distribution systems:

Name	Location	Number of Customers	Global s Ownership Interest
SAESA Group	Chile	617,000	100 %
Chilquinta	Chile	534,000	50 %
LDS	Peru	788,000	38 %
Total		1,939,000	

Chile and Peru

SAESA Group

Global owns a 99.99% equity interest in SAESA, 98.99% of Empresa Electrica de la Frontera S.A. (Frontel) and 100% of PSEG Generacion y Energia Chile Limitada (Generacion), collectively known as the SAESA Group. The SAESA Group consists of four distribution companies and one transmission company that provide electric service to 390 cities and towns over 900 miles in southern Chile and a generating company. The SAESA Group has 120 MW of installed generating capacity in operation (46 MW of natural gas-fired peaker capacity, 51 MW oil-fired, 21 MW hydro and 2 MW wind). The transmission company, Sistema de Transmision del Sur S.A. (STS), provides transmission services to electric generation facilities that have PPAs with distributors in Regions VIII, IX and X and has installed transformation capacity of 918 megavolt-amperes.

The SAESA Group also owned a 50% interest in an Argentine distribution company, Empresa de Energia Rio Negro S.A., which provides generation, transmission and distribution services to approximately 147,000 customers in the Province of Rio Negro, Argentina, but was sold in the last quarter of 2006. The management of the SAESA Group is organized and administered according to a centralized administrative structure designed to maximize operational synergies. For additional information related to the SAESA Group, see Item 1. Business Regulatory Issues.

Chilquinta and LDS

Global and Sempra Energy (Sempra), each own 50% of the shares of Chilquinta, an energy distribution company with numerous energy holdings, based in Valparaiso, Chile. Following the sale in 2004 of 12% of the shares of LDS to the public, Global and Sempra own 75.9% of LDS, an electric distribution company located in Lima, Peru. As part of the Chilquinta and LDS investments, Global and Sempra also own Tecnored and Tecsur, located in Chile and Peru, respectively. These companies provide procurement and contracting services to Chilquinta, LDS and others.

As equal partners, Global and Sempra share in the management of Chilquinta and LDS. However, Sempra has assumed lead operational responsibilities at Chilquinta, while Global has assumed lead operational responsibilities at LDS. The shareholders agreement provides for important veto rights over major partnership decisions including dividend policy, budget approvals, management appointments and indebtedness.

Chilquinta operates under a non-exclusive perpetual franchise within Chile s Region V which is located just north and west of Santiago. Global believes that direct competition for distribution customers would be uneconomical for potential competitors. LDS operates under an exclusive, perpetual franchise in the southern portion of the city of Lima and in an area just south of the city along the coast serving a population of approximately 3.2 million. Both Chilquinta and LDS purchase energy for distribution from generators in their respective markets on a contract basis. For additional information related to Chilquinta and LDS, see Item 1. Business Regulatory Issues.

ITEM 3. LEGAL PROCEEDINGS

PSE&G

In November 2001, Consolidated Edison Company of New York, Inc. (Con Edison) filed a complaint against PSE&G, PJM and NYISO with FERC asserting a failure to comply with agreements between PSE&G and Con Edison covering 1,000 MW of transmission. PSE&G denied the allegations set forth in the complaint. An Initial Decision issued by an ALJ in April 2002 upheld PSE&G s claim in part but also accepted Con Edison s contentions in part. In December 2002, FERC issued an order modifying the Initial Decision and remanding a number of issues to the ALJ for additional hearings, including issues related to the development of protocols to implement the findings of the order and regarding Phase II of the complaint. The ALJ issued an Initial Decision on the Phase II issues in June 2003 and in August 2004, FERC issued its decision on Phase II issues. While those decisions were largely favorable to PSE&G,

PSE&G sought rehearing as to certain issues, as did Con Edison. Those rehearing applications are currently pending.

The August 2004 order required that PJM, NYISO, Con Edison and PSE&G meet for the purpose of developing operational protocols to implement FERC s directives. On February 18, 2005, NYISO, PJM and

PSE&G submitted a joint compliance filing pursuant to FERC s August 2004 decision. FERC approved the joint proposals on May 18, 2005 and they took effect on July 1, 2005. In subsequent filings to FERC regarding the efficacy of these protocols, Con Edison continues to claim that the obligations under the agreements as interpreted by the FERC s orders are not being met. In December 30, 2005 and January 19, 2007 filings with FERC, Con Edison claims to have incurred $111 million in damages, and has requested FERC to require refunds of this amount. To the extent that this claim is directed at PSE&G, PSE&G believes that the claim has no legal basis and that, in any event, PSE&G has meritorious defenses to the claim. PJM, NYISO, Con Edison and PSE&G have agreed to a work plan under which they will attempt, during the Spring of 2007, to address operational issues associated with the protocols and to address Con Edison s refund claim. Con Edison has also requested that, if these settlement discussions are not successful, that FERC convene judge-mediated settlement discussions, to be followed by hearings if necessary. The scope of the discussions envisioned under the work plan are not currently expected, however, to encompass a comprehensive review of all matters raised in the November 2001 complaint or the pending rehearing requests of the FERC s orders. As this matter is currently pending before FERC, PSEG and PSE&G are unable to predict the outcome of this proceeding.

Energy Holdings

India

Global has a 20% ownership interest in PPN, which sells its output under a long-term PPA with the TNEB. TNEB has not made full payment to PPN for the purchase of energy under the PPA. Resolution of the past due receivables against which PPN has established reserves was expected to be achieved in 2005 by a joint working group including the Central Electric Authority (CEA), PPN and TNEB. However, in the latter part of 2005, the CEA reportedly stated that it had no jurisdiction in the matter and referred the parties to the Tamil Nadu Electric Regulatory Commission (TNERC). Neither PPN nor Global believe that TNERC has jurisdiction over Capital Cost Approval, a significant component of the receivables reserve. An adverse outcome concerning the disputed Capital Cost Approvals could result in impairment of this investment.

On March 26, 2004, Global and El Paso Energy Corporation (which sold its ownership interest in PPN in 2005) filed a notice of arbitration on behalf of PPN against TNEB under the arbitration clause of the PPA, asserting that they have the right as minority shareholders to protect the contractual rights of PPN where PPN has failed to exercise those rights itself. In response, PPN filed a petition for an anti-suit injunction against the arbitration. Global successfully defended against the petition in two lower courts. PPN has filed its final appeal in the Supreme Court of India (SLP Civil No. 23169). Hearings that began on January 24, 2005 have resulted in a stay of PSEG s continued actions in the arbitral court pending a decision by the Indian Supreme Court, which is expected in due course.

On December 30, 2006, Global petitioned the Company Law Board (Law Board) in Chennai, India to withdraw, without prejudice, its case against certain other members of PPN s Board of Directors, PPN management and certain other PPN shareholders for failure to act in PPN s best interest and other assertions. The Law Board issued the order as requested and the other parties did not object. The withdrawal of the Law Board case is expected to result in an eventual dismissal of the injunction against the arbitration described above.

As of December 31, 2006, Global s total investment in PPN was approximately $34 million.

Turkey

From about 1995 through 2001, Global and its partners expended approximately $12 million towards the construction of a power plant in the Konya-Ilgin region of Turkey. In 2001, Turkey passed legislation and otherwise deprived Global of rights and fair and equitable treatment and expropriated Global s Concession contract for the power plant project without compensation, despite the Turkish Government s obligation to compensate Global for its costs under the existing contract and Turkish law. In 2002, Global initiated arbitration before the International Centre for

Settlement of International Disputes seeking return of sunk costs, lost profits, interest and attorney fees and costs. A decision in this matter was made in January 2007 under which the Turkish Government will be required to pay Global and its partners approximately $20 million for sunk costs, interest and arbitration fees. After legal contingency fees, Global expects to receive approximately $7 million, after tax, for its share of the project. Global expects to receive payment in the second quarter of 2007.

PSEG, PSE&G, Power and Energy Holdings

In addition to matters discussed above, see information on the following proceedings at the pages indicated for PSEG and each of PSE&G, Power and Energy Holdings as noted:

(1) Page 16. (PSEG, PSE&G and Power) FERC proceedings with MISO and PJM relating to RTOR and SECA methodology, Docket No. ER05-6-000 et al.

(2) Page 16. (PSEG, PSE&G and Power) FERC proceeding relating to PJM Long-Term Transmission Rate Design, Docket No. EL05-121-000.

(3) Page 18. (Power) PSEG Power Connecticut s filing with FERC on November 17, 2004, Docket No. ER05-231-000, to request RMR compensation.

(4) Page 18. (PSEG, PSE&G and Power) PJM Reliability Pricing Model filed with FERC on August 31, 2005, Docket Nos. ERO5-1410-000 and EL05-148-000.

(5) Page 22. (PSEG and PSE&G) BPU proceeding on August 1, 2005 relating to ratepayer protections due to

repeal of PUHCA under the Energy Policy Act of 2005. Docket No. AX05070641.

(6) Page 23. (PSE&G) BPU proceeding relating to Electric Base Rate Case financial review, Docket No. ER02050303.

(7) Page 23. (PSE&G) PSE&G s BGSS Commodity filing with the BPU on May 28, 2004, Docket No. GR04050390.

(8) Page 24. (PSE&G) Remediation Adjustment Clause filing with the BPU on April 25, 2005, Docket No. GR05040383.

(9) Page 24. (PSE&G) PSE&G Petition for increase of gas base rates filed with BPU on September 30, 2005, Docket No. GR05100845.

(10) Page 24. (PSE&G) Deferral Proceeding filed with the BPU on August 28, 2002, Docket No. EX02060363, and Deferral Audit beginning on October 2, 2002 at the BPU, Docket No. EA02060366.

(11)

Page 25. (PSE&G) BPU Order dated December 23, 2003, Docket No. EO02120955 relating to the New Jersey Interim Clean Energy Program.

(12) Page 29. (Power) Power s Petition for Review filed in the United States Court of Appeals for the District of Columbia Circuit on July 30, 2004 challenging the final rule of the United States Environmental Protection Agency entitled National Pollutant Discharge Elimination System Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, now transferred to and venued in the United States Court of Appeals for the Second Circuit with Docket No. 04-6696-ag.

(13) Page 31. (Power) Filing of Complaint by Nuclear against the DOE on September 26, 2001 in the U.S. Court of Federal Claims, Docket No. 01-0551C seeking

damages caused by DOE s failure to take possession of spent nuclear fuel. The complaint was amended to include PSE&G as a prior owner in interest.

(14) Page 152. (PSE&G) Investigation Directive of NJDEP dated September 19, 2003 and additional investigation Notice dated September 15, 2003 by the EPA regarding the Passaic River site. Docket No. EX93060255.

(15) Page 153. (Power) PSE&G s MGP Remediation Program instituted by NJDEP s Coal Gasification Facility Sites letter dated March 25, 1988.

(16) Page 155. (Energy Holdings) Italian government investigation regarding allegations of violations of Prisma s air permit for the San Marco facility.

PSE&G and Power

In addition, see the following environmental related matters involving governmental authorities. PSE&G and Power do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on their respective financial condition, results of operations and net cash flows.

(1) Claim made in 1985 by the U.S. Department of the Interior under CERCLA with respect to the Pennsylvania Avenue and Fountain Avenue municipal landfills in Brooklyn, New York, for damages to

natural resources. The U.S. Government alleges damages of approximately $200 million. To PSE&G s knowledge there has been no action on this matter since 1988.

(2) Duane Marine Salvage Corporation Superfund Site is in Perth Amboy, Middlesex County, New Jersey. The EPA had named PSE&G as one of several potentially responsible parties (PRPs) through a series of administrative orders between December 1984 and March 1985. Following work performed by the PRPs, the EPA declared on May 20, 1987 that all of its administrative orders had been satisfied. The NJDEP, however, named PSE&G as a PRP and issued its own directive dated October 21, 1987. Remediation is currently ongoing.

(3) Various Spill Act directives were issued by NJDEP to PRPs, including PSE&G with respect to the PJP Landfill in Jersey City, Hudson County, New Jersey, ordering payment of costs associated with operation and maintenance, interim remedial measures and a Remedial Investigation and Feasibility Study (RI/FS) in excess of $25 million. The directives also sought reimbursement of NJDEP s past and future oversight costs and the costs of any future remedial action.

(4) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presents the design details that will implement the EPA s selected remediation remedy. The costs of remedy implementation are estimated to range from $14 million to $24 million. PSE&G s share of the remedy implementation costs are estimated between $4 million and $8 million.

(5) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G s Trenton Switching Station property. PSE&G entered into a memorandum of agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination at the site.

(6) The NJDEP assumed control of a former petroleum products blending and mixing operation and waste oil recycling facility in Elizabeth, Union County, New Jersey (Borne Chemical Co. site) and issued various directives to a number of entities, including PSE&G, requiring performance of various remedial actions. PSE&G s nexus to the site is based upon the shipment of certain waste oils to the site for recycling. PSE&G and certain of the other entities named in NJDEP directives are members of a PRP group that have been working together to satisfy NJDEP requirements including: funding of the site security program; containerized waste removal; and a site remedial investigation program.

(7) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a potentially responsible party (PRP) with respect to contamination in Berry s Creek in Bergen County, New Jersey and requesting that the PRPs perform a Remedial Investigation/Feasibility Study (RI/FS) on Berry s Creek and the connected tributaries and wetlands. Berry s Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could be completed in approximately five years at a total cost of approximately $18 million. PSE&G and Power are unable to predict the outcome of this matter; however, the related costs of this study are not expected to be material.

(8) The EPA sent PSE&G and three other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in the Newark Bay Study Area, which it defined as Newark Bay and portions of the Hackensack River, the Arthur Kill, and the Kill Van Kull. The notice letter requested that PSE&G participate and fund the EPA-approved study in the Newark Bay Study Area and encouraged PSE&G to contact Occidental Chemical Corporation (OCC) to discuss participating in the RI/FS that OCC is conducting in the Newark Bay Study Area. EPA considers the Newark Bay Study Area, along with the Passaic River Study Area, to be part of the Diamond Alkali Superfund Site. The notice states EPA s belief that hazardous substances were released from sites owned by PSE&G

and located on the Hackensack River. The sites included two operating electric generating stations (Hudson and Kearny Sites), and one former MGP. PSE&G s costs to clean up former MGPs are recoverable from utility customers through the SBC. The Hudson and Kearny Sites were transferred to Power in August 2000. Power assumed any environmental liabilities of PSE&G associated with the electric generating stations that PSE&G transferred to it, including the Hudson and Kearny Sites. Power has provided notice to insurers concerning this potential claim. PSE&G and Power are unable to estimate the cost of the investigation at this time.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

PSEG s Annual Meeting of Stockholders was held on November 21, 2006. Proxies for the meeting were solicited pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management s nominees as listed in the proxy statement and all of management s nominees were elected to the Board of Directors. Details of the voting are provided below:

	Votes For	**Votes Withheld**
Proposal:		
Election of Directors		
Caroline Dorsa	209,520,856	10,007,648
E. James Ferland	207,098,164	12,430,340
Albert R. Gamper, Jr.	209,440,773	10,087,731
Ralph Izzo	208,006,028	11,522,476

	Votes For	**Votes Against**	**Abstentions**	**Broker Non-Votes**
Proposal:				
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	214,052,603	3,273,939	2,210,538	
Proposal:				
Stockholder Proposal	31,230,349	144,720,275	4,552,843	

PART II

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

PSEG

PSEG s Common Stock is listed on the New York Stock Exchange, Inc. As of December 31, 2006, there were 94,972 holders of record.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2001 in PSEG common stock, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2001	2002	2003	2004	2005	2006
PSEG	100.00	80.66	115.97	143.91	187.34	198.28
S&P 500	100.00	77.95	100.27	111.15	116.59	134.96
DJ Utilities	100.00	76.68	98.97	128.72	160.85	187.61
S&P Electrics	100.00	84.92	105.17	132.94	156.24	192.43

The following table indicates the high and low sale prices for PSEG s Common Stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend Per Share
2006:			
First Quarter	$ 72.45	$ 63.97	$ 0.57
Second Quarter	$ 67.63	$ 59.00	$ 0.57
Third Quarter	$ 72.61	$ 60.47	$ 0.57
Fourth Quarter	$ 68.10	$ 59.12	$ 0.57
2005:			
First Quarter	$ 56.23	$ 49.32	$ 0.56
Second Quarter	$ 61.66	$ 52.00	$ 0.56
Third Quarter	$ 68.47	$ 59.09	$ 0.56
Fourth Quarter	$ 67.58	$ 56.05	$ 0.56

In January 2007, PSEG s Board of Directors approved a one and one half-cent increase in its quarterly common stock dividend, from $0.57 to $0.585 per share, for the first quarter of 2007. This increase reflects an indicated annual dividend rate of $2.34 per share. For additional information concerning dividend payments, dividend history, policy and potential preferred voting rights, restrictions on payment and common stock repurchase programs, see Item 7. MD&A Overview of 2006 and Future Outlook and Liquidity and Capital Resources and Note 9. Schedule of Consolidated Capital Stock and Other Securities of the Notes.

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The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2006:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (#)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ($)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (#)
Equity compensation plans approved by security holders	1,623,169	42.42	11,851,709
Equity compensation plans not approved by security holders	192,833	44.37	1,909,235 (A)
Total	1,816,002	42.63	13,760,944

(A) Shares issuable under the PSEG Employee Stock Purchase Plan, Compensation Plan for Outside Directors and Stock Plan for Outside Directors.

For additional discussion of specific plans concerning equity-based compensation, see Note 17. Stock Options and Employee Stock Purchase Plan of the Notes.

PSE&G

All of the common stock of PSE&G is owned by PSEG. For additional information regarding PSE&G s ability to continue to pay dividends, see Item 7. MD&A Overview of 2006 and Future Outlook.

Power

All of Power s outstanding limited liability company membership interests are owned by PSEG. For additional information regarding Power s ability to pay dividends, see Item 7. MD&A Overview of 2006 and Future Outlook.

Energy Holdings

All of Energy Holdings outstanding limited liability company membership interests are owned by PSEG. For additional information regarding Energy Holdings ability to pay dividends, see Item 7. MD&A Overview of 2006 and Future Outlook.

ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the Management s Discussion and Analysis (MD&A) and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

	For the Years Ended December 31,				
	2006	2005	2004	2003	2002
	(Millions, where applicable)				
Operating Revenues(A)	$ 12,164	$ 12,164	$ 10,610	$ 10,839	$ 8,037
Income from Continuing Operations(B)	$ 752	$ 886	$ 795	$ 855	$ 403
Net Income	$ 739	$ 661	$ 726	$ 1,160	$ 235
Earnings per Share:					
Income from Continuing Operations:					
Basic(B)	$ 2.99	$ 3.69	$ 3.35	$ 3.75	$ 1.94
Diluted(B)	$ 2.98	$ 3.63	$ 3.34	$ 3.75	$ 1.94
Net Income:					
Basic	$ 2.94	$ 2.75	$ 3.06	$ 5.08	$ 1.13
Diluted	$ 2.93	$ 2.71	$ 3.05	$ 5.07	$ 1.13
Dividends Declared per Share	$ 2.28	$ 2.24	$ 2.20	$ 2.16	$ 2.16
As of December 31:					
Total Assets	$ 28,570	$ 29,821	$ 29,260	$ 28,132	$ 26,113
Long-Term Obligations(C)	$ 10,417	$ 11,329	$ 12,663	$ 12,729	$ 10,889

(A) Includes adjustments to net revenues and expenses for prior years related to one of PSE&G s contracts that had previously been recorded on a gross basis.

For the years ended December 31, 2005, 2004, 2003 and 2002, the adjustments reduced Operating Revenues by $214 million, $162 million, $142 million and $90 million, respectively, with no impact on Operating Income. See Note 1. Organization and Summary of Significant Accounting Policies for additional information.

(B) Income from Continuing Operations for 2006 include an after-tax charge of $178 million, or $0.70 per share related to the sale of RGE. Income from Continuing Operations for 2002 include after-tax charges of $368 million, or $1.76 per share, related to losses from Energy Holdings Argentine investments.

(C) Includes capital lease obligations.

PSE&G

The information presented below should be read in conjunction with the MD&A, the Consolidated Financial Statements and the Notes.

	For the Years Ended December 31,				
	2006	2005	2004	2003	2002
			(Millions)		
Operating Revenues(A)	$ 7,569	$ 7,514	$ 6,810	$ 6,598	$ 5,829
Income Before Extraordinary Item	$ 265	$ 348	$ 346	$ 247	$ 205
Net Income	$ 265	$ 348	$ 346	$ 229	$ 205
As of December 31:					
Total Assets	$ 14,553	$ 14,297	$ 13,586	$ 13,177	$ 12,867
Long-Term Obligations	$ 4,711	$ 4,745	$ 4,877	$ 5,129	$ 5,050

(A) Includes adjustments to net revenues and expenses for prior years related to one of PSE&G s contracts that had previously been recorded on a gross basis. For the years ended December 31, 2005, 2004, 2003 and 2002, the adjustments reduced Operating Revenues by $214 million, $162 million, $142 million and $90 million, respectively, with no impact on Operating Income. See Note 1. Organization and Summary of Significant Accounting Policies for additional information.

Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Energy Holdings

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G), PSEG Power LLC (Power) and PSEG Energy Holdings L.L.C. (Energy Holdings). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G, Power and Energy Holdings each make representations only as to itself and make no other representations whatsoever as to any other company.

OVERVIEW OF 2006 AND FUTURE OUTLOOK

PSEG, PSE&G, Power and Energy Holdings

PSEG s business consists of four reportable segments, which are PSE&G, Power and the two direct subsidiaries of Energy Holdings: PSEG Global L.L.C. (Global) and PSEG Resources L.L.C. (Resources). The following discussion relates to the markets in which PSEG s subsidiaries compete, the corporate strategy for the conduct of PSEG s businesses within these markets and significant events that have occurred during 2006 and expectations for 2007 for PSE&G, Power and Energy Holdings, as well as the key factors that will drive the future performance of these businesses.

Termination of Merger Agreement

On December 20, 2004, PSEG entered into an Agreement and Plan of Merger (Merger Agreement) with Exelon Corporation (Exelon) providing for a merger of PSEG with and into Exelon (Merger). On September 14, 2006, PSEG received from Exelon a formal notice terminating the Merger under the provisions of the Merger Agreement.

PSE&G

PSE&G operates as an electric and gas public utility in New Jersey under cost-based regulation by the New Jersey Board of Public Utilities (BPU) for its distribution operations and by the Federal Energy Regulatory Commission (FERC) for its electric transmission and wholesale sales operations.

Consequently, the earnings of PSE&G are largely determined by the regulation of its rates by those agencies. In February 2007, the BPU approved the results of New Jersey s annual Basic Generation Service (BGS)-Fixed Price (FP) and BGS-Commercial and Industrial Energy Price (CIEP) auctions and PSE&G successfully secured contracts to provide the electricity requirements for the majority of its customers needs.

Overview of 2006

During 2006 PSE&G:

reached a settlement agreement in the Gas Base Rate Case with the BPU Staff, New Jersey Public

Ratepayer Advocate (RPA) and other intervening parties which was approved by the BPU on November 9, 2006 and provides for an annual increase in gas revenues of $40 million, an adjustment to lower book depreciation expense for PSE&G by approximately $26 million annually and the amortization of accumulated cost of removal that will further reduce depreciation and amortization expense by $13 million annually for five years.

reached a settlement agreement in the Electric Distribution Financial Review with the BPU Staff, RPA and other intervening parties concerning the excess depreciation rate credit which was approved by the BPU on November 9, 2006 and authorizes a reduction in the credit to $22 million, resulting in additional revenue to PSE&G of approximately $47 million annually based on current sales volumes.

Future Outlook

PSE&G believes that the decisions in November 2006 for both gas and electric base rates positions it to earn reasonable returns on investment in the future. The full year impact of these decisions combined with an anticipated return to more normal weather conditions is expected to improve PSE&G s margins for 2007 and beyond.

The risks to PSE&G s business generally relate to the treatment of the various rate and other issues by the state and federal regulatory agencies, specifically the BPU and FERC. PSE&G s success will depend, in part, on its ability to attain a reasonable rate of return, continue cost containment initiatives, maintain system reliability and safety levels and continued recovery, with an adequate return, of the regulatory assets it has deferred and the investments it plans to make in its electric and gas transmission and distribution system. Since PSE&G earns no margin on the commodity portion of its electric and gas sales through tariff agreements, there is no anticipated commodity price volatility for PSE&G.

Power

Power is an electric generation and wholesale energy marketing and trading company that is focused on a generation market in the Northeast and Mid Atlantic U.S. Power s principal operating subsidiaries, PSEG Fossil LLC (Fossil), PSEG Nuclear LLC (Nuclear) and PSEG Energy Resources & Trade LLC (ER&T) are regulated by FERC. Through its subsidiaries, Power seeks to balance its generation production, fuel requirements and supply obligations through integrated energy marketing and trading, enhance its ability to produce low-cost energy through efficient nuclear and coal operations and pursue modest growth based on market conditions. Changes in the operation of Power s generating facilities, fuel and capacity prices, expected contract prices, capacity factors or other assumptions could materially affect its ability to meet earnings targets and/or liquidity requirements. In addition to the electric generation business described above, Power s revenues include gas supply sales under the Basic Gas Supply Service (BGSS) contract with PSE&G.

As a merchant generator, Power s profit is derived from selling under contract or on the spot market a range of diverse products such as energy, capacity, emissions credits, congestion credits, and a series of energy-related products that the system operator uses to optimize the operation of the energy grid, known as ancillary services. Accordingly, the prices of commodities, such as electricity, gas, coal and emissions, as well as the availability of Power s diverse fleet of generation units to produce these products, can have a material effect on Power s profitability. In recent years, the prices at which transactions are entered into for future delivery of these products, as evidenced through the market for forward contracts at points such as PJM Interconnection, L.L.C. (PJM) West, have escalated considerably over historical prices. Broad market price increases such as these are expected to have a positive effect on Power s results. Historically, Power s nuclear and coal-fired facilities have produced over 50% and 25% of Power s production, respectively. With the vast majority of its power sourced from lower-cost units, the rise in electric prices is anticipated to yield higher near-term margins for Power. Power anticipates recognizing these higher near-term margins, especially on the portion of its output that was more recently contracted or sold on the spot market. Over a longer-term horizon, if these higher prices are sustained at prices reflective of what the current forward markets indicate, it would yield an attractive environment for Power to contract the sale of its anticipated output, allowing for potentially sustained higher profitability than recognized in prior years. These escalated prices also increase the cost of replacement power, thereby placing incremental risk on the operations of the generating units to produce these products.

Power seeks to mitigate volatility in its results by contracting in advance for a significant portion of its anticipated electric output and fuel needs. Power believes this contracting strategy increases stability of earnings and cash flow. By keeping some portion of its output uncontracted, Power is able to retain some exposure to market changes as well as provide some protection in the event of unexpected generation outages.

Power seeks to sell a portion of its anticipated low-cost nuclear and coal-fired generation over a multi-year forward horizon, normally over a period of approximately two to four years. As of February 14, 2007, Power has contracted for approximately 100% of its anticipated 2007 nuclear and coal-fired generation, with 90% to 100% contracted for 2008 and 35% to 50% contracted for 2009, with a modest amount contracted beyond 2009.

Power has also entered into contracts for the future delivery of nuclear fuel and coal to support its contracted sales discussed above. As of February 1, 2007, Power had contracted for 100% of its anticipated nuclear uranium fuel needs through 2011, and approximately 70% of its average anticipated coal needs, including transportation, through 2009.

These estimates are subject to change based upon the level of operation, and in particular for coal, are subject to market demands and pricing.

By contrast, Power takes a more opportunistic approach in hedging its anticipated natural gas-fired generation. The generation from these units is less predictable, as these units are generally dispatched only when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units generally provide a lower contribution to the margin of Power than either the nuclear or coal units. Power will generally purchase natural gas as gas-fired generation is required to supply forward sale commitments.

In a changing market environment, this hedging strategy may cause Power s realized prices to be materially different than current market prices. At the present time, some of Power s existing contractual obligations, entered into during lower-priced periods, are anticipated to result in lower margins than would have been the case if no or little hedging activity had been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins in excess of those implied by the then current market.

Overview of 2006

During 2006, FERC issued certain orders related to market design that have changed the nature of capacity payments in the New England Power Pool (NEPOOL) and are scheduled to change the nature of payments in PJM. In PJM, the Reliability Pricing Model (RPM) will provide generators with differentiated capacity payments based upon the location of their respective facilities. Similarly, the Forward Capacity Market (FCM) settlement in NEPOOL provides for locational capacity payments. FERC has approved the market changes in each of these markets, with the anticipated start date for RPM set for June 1, 2007 and FCM transition period having begun on December 1, 2006. Power currently receives fixed Reliability-Must-Run (RMR) payments in PJM and NEPOOL for certain of its facilities which are provided to ensure the continued availability of those facilities.

Also during 2006 Power:

commenced commercial operations of its 1,186 MW, natural gas-fired combined cycle power generation plant in Linden, New Jersey;

reached an agreement with the EPA and NJDEP that will allow the continued operation of the Hudson facility and extends for four years the deadline for installing environmental controls beyond the previous December 31, 2006 deadline;

announced its plans to resume direct management of the Salem and Hope Creek facilities before the expiration of the Operating Service Contract with Exelon Generation and to have the senior management team at those facilities to become employees of Power effective January 1, 2007; and

entered into an agreement to sell its Lawrenceburg Energy Center, a 1,080 MW gas-fired combined cycle electric generating plant in Lawrenceburg, Indiana.

Future Outlook

Power expects margin improvements in 2007 as higher prices for its nuclear and coal output are realized due to the rolling nature of its forward hedge positions and the expiration of its contract in Connecticut. The sale of Lawrenceburg and anticipated improvements in margins on serving the BGSS contract are also expected to benefit future results.

In addition, Power believes that the redesign in capacity markets, discussed above, could lead to changes in the value of the majority of its generating capacity and result in incremental margin of $100 million to $150 million in 2007, with higher increases in future years as the full year impact is realized and existing capacity contracts expire.

A key factor in Power s ability to achieve its objectives is its capability to operate its nuclear and fossil stations at sufficient capacity factors to limit the need to purchase higher-priced electricity to satisfy its obligations. Power s ability to achieve its objectives will also depend on the implementation of reasonable capacity markets. Power must also be able to effectively manage its construction projects and continue to economically operate its generation facilities under increasingly stringent environmental requirements. In addition, with an increase in competition and market complexity and constantly changing forward prices, there is no assurance that Power will be able to contract its output at attractive prices. While these increases may have a potentially significant beneficial impact on margins, they could also raise any replacement power costs that Power may incur in the event of unanticipated outages, and could also further increase liquidity requirements as a result of contract obligations. Power could also be impacted by the lack of consistent rules in markets outside of PJM, including rate-regulated utility ownership of generation and other regulatory actions favoring non-competitive markets. For additional information on liquidity requirements, see Liquidity and Capital Resources.

Energy Holdings

Energy Holdings operations are principally conducted through its subsidiaries Global, which has invested in international, rate-regulated distribution companies and domestic and international generation companies, and Resources, which primarily invests in energy-related leveraged leases.

Global

Global has reduced its international risk by opportunistically monetizing investments that no longer had a strategic fit. During the past three years, Global has reduced its overall investments from $2.6 billion to $1.9 billion, driven by sales of over $1 billion of investments in China, Brazil, Poland, India, Africa and the Middle East. See Note 4. Discontinued Operations, Acquisitions, Dispositions and Impairments of the Notes, for a discussion of these sales. The decrease in Global s portfolio size due to the above sales was partially offset by strong earnings from its Texas merchant generation business and its electric distribution companies in Chile and Peru. Approximately 65% of Global s remaining investments are in Chile and Peru with another 27% in the United States. Other modest sized investments in Italy, India and Venezuela comprise the remaining 8% of Global s portfolio.

As a result of the investment sales, approximately 50% of Global s future earnings is expected to be derived from its domestic generation business, of which over half is from its 2,000 MW gas-fired combined cycle merchant generation business in Texas with the balance from its 12 fully contracted generating facilities in which Global s ownership percentage equates to nearly 400 MW. The other 50% of Global s earnings is expected to be essentially from three rate-regulated electric distribution businesses in Chile and Peru which serve approximately two million customers and a 183 MW hydro generation facility in Peru. The regulatory environment in both Chile and Peru has generally been constructive since Global acquired these investments. Chile maintains an investment grade rating and Peru s rating, although non-investment grade, has improved.

Energy Holdings continues to review Global s portfolio, with a focus on its international investments. As part of this review, Energy Holdings considers the returns of its remaining investments against alternative investments across the PSEG companies, while considering the strategic fit and relative risks of these businesses**.** Energy Holdings is also considering the impact of any potential sales of its investments on its targeted credit metrics and debt service requirements and at present, Global anticipates that it will take into consideration an appropriate balance of the use of proceeds from any sales with returns of equity to PSEG and debt repayments.

Resources

Resources primarily has invested in energy-related leveraged leases. Resources is focused on maintaining its current investment portfolio and does not expect to make any new investments.

Overview of 2006

During 2006, Energy Holdings had over $600 million of proceeds from the sales of Global s investments in two generating stations in Poland, the sale of its interest in RGE, a distribution company in Brazil and from its sale of its remaining 46% interest in Dhofar Power.

Energy Holdings used this cash as well as funds on hand at December 31, 2005 and cash from operations to return $520 million of capital to PSEG, redeem all $309 million of its 7.75% 2007 Senior Notes in January 2006 and redeem $300 million of its 8.625% 2008 Senior Notes in October 2006.

Future Outlook

Energy Holdings expects decreased margins at Global in 2007 primarily relating to the absence of mark-to-market gains, a slight reduction in spark spreads and anticipated maintenance outages at Texas Independent Energy L.P. (TIE) s plants. Also contributing to the expected decrease are higher taxes, the impact of adopting FIN 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB

Statement 109 (FIN 48) and related standards and lower earnings due to asset sales partly offset by the impact of early adoption of FAS 157.

As discussed above, Global s earnings are primarily derived from its investments in the United States, Chile and Peru. As such, Global s success will depend on continued strong energy markets in Texas and the economic and efficient operation of its electric distribution companies in Chile and Peru, including its ability to achieve reasonable rates and meeting expected growth in usage. The success of Global s foreign investments will also depend on stable political, regulatory and economic policies, including foreign currency exchange rates and interest rates, particularly for Chile and Peru.

Resources ability to realize tax benefits associated with its leveraged lease investments is dependent upon taxable income generated by its affiliates. Resources earnings and cash flows are expected to decrease in the future as the investment portfolio matures. Resources faces risks with regard to the creditworthiness of its counterparties; the weighted average credit rating of its lessees at December 31, 2006 was A /A3. Certain lessees ratings are below investment grade. The lease structures have various credit enhancement mechanisms. Resources monitors the credit rating of the lessees very closely, calling letters of credit and taking other measures when appropriate.

Energy Holdings also faces risks related to the tax treatment of uncertain tax positions which will be impacted by new accounting guidance under FIN 48 and FASB Staff Position No. FAS 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction , both of which are effective as of January 1, 2007. Based on its evaluation of this new guidance, Energy Holdings estimates that it will record a reduction to Retained Earnings of approximately $190 million to $215 million, effective January 1, 2007. In addition, this new guidance will have an impact on Energy Holdings future revenues and earnings, including an anticipated earnings reduction of $25 million to $35 million in 2007, as compared to 2006, which represents the majority of the anticipated impact on PSEG. See Note 2. Recent Accounting Standards of the Notes for further discussion.

RESULTS OF OPERATIONS

PSEG, PSE&G, Power and Energy Holdings

Net Income for the year ended December 31, 2006 was $739 million or $2.93 per share of common stock, diluted, based on approximately 252 million average shares outstanding. Net Income for the year ended December 31, 2005 was $661 million or $2.71 per share of common stock, diluted, based on approximately 244 million average shares outstanding. Included in 2006 Net Income was a $208 million after-tax estimated loss on disposal related to an agreement to sell Lawrenceburg. Included in 2005 Net Income was a $178 million after-tax loss from the sale of Power s Waterford generation facility. See Note 4. Discontinued Operations, Acquisitions, Dispositions and Impairments of the Notes. Net Income for the year ended December 31, 2004 was approximately $726 million or $3.05 per share of common stock, diluted, based on approximately 238 million average shares outstanding.

	Earnings (Losses) Years Ended December 31,		
	2006	2005	2004
		(Millions)	
PSE&G	$ 265	$ 348	$ 346
Power	515	434	367
Energy Holdings:			
Global	(11)	112	93
Resources	63	92	68
Other(A)	(3)	(5)	(10)
Total Energy Holdings	49	199	151
Other(B)	(77)	(95)	(69)
PSEG Income from Continuing Operations(C)	752	886	795
Loss from Discontinued Operations, including Gain (Loss) on Disposal(D)	(13)	(208)	(69)
Cumulative Effect of a Change in Accounting Principle(E)		(17)	
PSEG Net Income	$ 739	$ 661	$ 726

	Contribution to Earnings Per Share (Diluted)(F) Years Ended December 31,		
	2006	2005	2004
PSE&G	$ 1.05	$ 1.42	$ 1.45
Power	2.04	1.78	1.55
Energy Holdings:			
Global	(0.04)	0.46	0.39

Resources	0.25	0.38	0.28
Other(A)	(0.01)	(0.02)	(0.04)
Total Energy Holdings	0.20	0.82	0.63
Other(B)	(0.31)	(0.39)	(0.29)
PSEG Income from Continuing Operations (C)	2.98	3.63	3.34
Loss from Discontinued Operations, including Gain (Loss) on Disposal(D)	(0.05)	(0.85)	(0.29)
Cumulative Effect of a Change in Accounting Principle(E)		(0.07)	
PSEG Net Income	$ 2.93	$ 2.71	$ 3.05

(A) Other activities include non-segment amounts of Energy Holdings and its subsidiaries and intercompany eliminations. Non-segment amounts include interest on certain financing transactions and certain other administrative and general expenses at Energy Holdings.

(B) Other activities include non-segment amounts of

PSEG (as parent company) and intercompany eliminations. Specific amounts include interest on certain financing transactions, Merger expenses and certain administrative and general expenses at PSEG (as parent company).

(C) Global s Income from Continuing Operations for 2006 includes the $178 million after-tax loss on the sale of Rio Grande Energia S.A. (RGE) in June 2006.

(D) Includes Discontinued Operations of Lawrenceburg, Skawina and Elcho in 2006, 2005 and 2004, Waterford in 2005 and 2004 and Carthage Power Company (CPC) in 2004 as well as an estimated loss in 2006 on the disposal of Lawrenceburg, the gain on disposal of Elcho and Skawina in 2006, the loss on disposal of Waterford in 2005 and the gain on disposal of CPC in 2004. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

(E) Relates to the adoption of FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. in 2005. See Note 3. Asset

Retirement Obligations of the Notes.

(F) Earnings Per Share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct interest in PSEG s assets and liabilities as a whole.

The year over year changes in PSEG s Net Income primarily relates to changes in Net Income for PSE&G, Power and Energy Holdings, discussed below. Also included in PSEG s results for each of the periods were financing costs at the parent level and Merger and Merger-related costs. For the year ended December 31, 2006, PSEG s after-tax costs were $77 million, a decrease $18 million as compared to 2005. For the year ended December 31, 2005, PSEG s after-tax costs were $95 million, an increase of $26 million as compared to 2004. The primary reason for these changes was the change in after-tax Merger and Merger-related costs which amounted to $8 million, $32 million and $4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

PSEG

	For the Years Ended December 31,			2006 vs 2005		2005 vs 200
	2006	**2005**	**2004**	**Increase (Decrease)**	**%**	**Increase (Decrease)**
		(Millions)				**(Millions)**
Operating Revenues	$ 12,164	$ 12,164	$ 10,610	$		$ 1,554
Energy Costs	$ 6,769	$ 7,040	$ 5,824	$ (271)	(4)	$ 1,216
Operation and Maintenance	$ 2,297	$ 2,282	$ 2,147	$ 15	1	$ 135
Write-down of Assets	$ 318	$	$	$ 318	N/A	$
Depreciation and	$ 832	$ 731	$ 683	$ 101	14	$ 48

Amortization											
Income from Equity Method Investments	$	120	$	124	$	119	$	(4)	(3)	$	5
Other Income and Deductions	$	83	$	140	$	121	$	(57)	(41)	$	19
Interest Expense	$	(808)	$	(784)	$	(774)	$	24	3	$	10
Income Tax Expense	$	(454)	$	(560)	$	(484)	$	(106)	(19)	$	76
Loss from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	$	(13)	$	(208)	$	(69)	$	(195)	(94)	$	139
Cumulative Effect of a Change in Accounting Principle, net of tax	$		$	(17)	$		$	17	N/A	$	(17)

PSEG s results of operations are primarily comprised of the results of operations of its operating subsidiaries, PSE&G, Power and Energy Holdings, excluding changes related to intercompany transactions, which are eliminated in consolidation. It also includes certain financing costs at the parent company. For additional information on intercompany transactions, see Note 21. Related-Party Transactions of the Notes. For a discussion of the causes for the variances at PSEG in the table above, see the discussions for PSE&G, Power and Energy Holdings that follow.

PSE&G

For the year ended December 31, 2006, PSE&G had Net Income of $265 million, a decrease of $83 million as compared to the year ended December 31, 2005. This decrease was primarily due to delayed decisions in its electric and gas base rate cases combined with the decline in electric and gas delivery volumes. Gas delivery volumes dropped 10% in 2006 as compared with 2005 and electric delivery volumes were down 3%. The weather was the primary cause of these declines with a drop of 16% in the number of degree days impacting gas. Gas commodity prices were extremely high early in 2006, which also contributed to a decline in weather normalized sales. THI hours were normal in 2006 but 18% less than 2005 negatively impacting electric sales.

For the year ended December 31, 2005, PSE&G had Net Income of $348 million, a $2 million increase as compared to the year ended December 31, 2004. This slight increase resulted primarily from higher margins, due to favorable weather conditions, and reduced interest expense being substantially offset by higher Operation and Maintenance costs.

The year-over-year detail for these variances for these periods are discussed in more detail below:

	For the Years Ended December 31,			2006 vs 2005		2005 vs 2004	
	2006	2005	2004	Increase (Decrease)	%	Increase (Decrease)	%
		(Millions)				(Millions)	
Operating Revenues	$ 7,569	$ 7,514	$ 6,810	$ 55	1	$ 704	10
Energy Costs	$ 4,884	$ 4,756	$ 4,122	$ 128	3	$ 634	15
Operation and Maintenance	$ 1,160	$ 1,151	$ 1,083	$ 9	1	$ 68	6
Depreciation and Amortization	$ 620	$ 553	$ 523	$ 67	12	$ 30	6
Other Income and Deductions	$ 22	$ 12	$ 11	$ 10	83	$ 1	9
Interest Expense	$ (346)	$ (342)	$ (362)	$ 4	1	$ (20)	(6)
Income Tax Expense	$ (183)	$ (235)	$ (246)	$ (52)	(22)	$ (11)	(4)

Operating Revenues

PSE&G has three sources of revenue: commodity revenues from the sales of energy to customers and in the PJM spot market; delivery revenues from the transmission and distribution of energy through its system; and other operating revenues from the provision of various services.

PSE&G makes no margin on gas commodity sales as the costs are passed through to customers. The difference between the gas costs paid under the requirements contract for residential customers and the revenues received from residential customers is deferred and collected from or returned to customers in future periods. Gas commodity prices fluctuate monthly for commercial and industrial customers and annually through the BGSS tariff for residential customers. In addition, for residential gas customers, PSE&G has the ability to adjust rates upward two additional times and downward at any time, if warranted, between annual BGSS proceedings.

PSE&G makes no margin on electric commodity sales as the costs are passed through to customers. PSE&G secures its electric commodity through the annual BGS auction. Electric commodity supply prices are set based on the results of these auctions for residential and smaller industrial and commercial customers, and are translated into seasonally-adjusted fixed rates. Electric supply for larger industrial and commercial customers is provided at a rate principally based on the hourly PJM real-time energy price. Customers may obtain their electric supply through either the BGS default electric supply service or through competitive third-party electric suppliers, and the majority of the customers subject to hourly pricing are currently receiving electric supply from third-party suppliers. Any differences between amounts paid by PSE&G to BGS suppliers for electric commodity, and the amounts of electric commodity revenue collected from customers is deferred and collected or returned to customers in subsequent months.

The $55 million increase for the year ended December 31, 2006, as compared to 2005 was due to increases of $78 million in commodity revenues and $3 million in other operating revenues offset by a decrease of $26 million in delivery revenues.

The $704 million increase for the year ended December 31, 2005, as compared to 2004 was due to increases of $624 million in commodity revenues, $74 million in delivery revenues and $6 million in other operating revenues.

Commodity

The $78 million increase in commodity revenues for the year ended December 31, 2006, as compared to 2005, was due to an increase in electric commodity revenues of $213 million offset by a decrease of $135 million in gas commodity revenues. The increase in electric revenues was primarily due to $299 million in higher BGS revenues (higher auction prices of $346 million offset by reduced sales of $47 million) offset by $85 million in lower Non-Utility Generation (NUG) revenues (lower prices of $82 million and by $3 million for lower volumes). The decrease in gas revenues was primarily due to $317 million in lower volumes due to weather and $58 million due to the expiration of the Third Party Shopping Incentive Clause in July 2005. There is a corresponding $58 million increase in delivery revenues. These were offset by $240 million in higher BGSS prices.

The $624 million increase in commodity revenues for the year ended December 31, 2005, as compared to 2004, was due to increases in electric and gas revenues of $313 million and $311 million, respectively. The increase in electric revenues was primarily due to $216 million in higher BGS revenues (higher auction prices of $148 million and increased sales of $68 million) and $97 million in higher NUG revenues (higher prices of $98 million offset by $1 million for lower volumes). The increase in gas revenues was primarily due to $291 million in higher BGSS prices and $62 million in higher volumes due to weather offset by the decrease of $42 million due to the expiration of the Third Party Shopping Incentive Clause in July 2005. There is a corresponding $42 million increase in delivery revenues.

Delivery

The $26 million decrease in delivery revenues for the year ended December 31, 2006, as compared to 2005, was due to a $27 million decrease in gas and a $1 million increase in electric revenues. The gas decrease was due to $101 million in lower volumes primarily due to weather offset by $74 million in increased prices, $58 million of which was due to the expiration of the Third Party Shopping Incentive Clause in July 2005, described above in commodity revenues, $8 million due to rate relief effective November 9, 2006 and $8 million due to the Societal Benefits Clause (SBC) November 1, 2006 rate increase. The electric increase was due primarily to $13 million in higher securitization tariff rates and $8 million from a rate increase effective November 9, 2006, offset by $20 million in lower volumes due to weather.

The $74 million increase in delivery revenues for the year ended December 31, 2005, as compared to 2004, was due to increases in electric and gas revenues of $67 million and $7 million, respectively. The electric increase was due primarily to $55 million in higher volumes due to weather and $12 million in higher rates. The gas increase was due to the expiration of the Third Party Shopping Incentive in July 2005, resulting in an increase of $42 million in delivery revenues with a corresponding offset in commodity revenues, described above, and a $12 million increase in SBC revenues (offset in Operation and Maintenance Costs below). This was offset by $9 million in lower volume and demand revenues due to weather and $37 million due to the expiration of the Gas Cost Underrecovery Adjustment (GCUA) clause in January 2005.

Operating Expenses

Energy Costs

The $128 million increase for the year ended December 31, 2006, as compared to 2005, was comprised of an increase of $211 million in electric costs offset by a decrease of $83 million in gas costs. The increase in electric costs was caused by $255 million or 16% in higher prices for BGS and NUG purchases offset by $47 million in lower BGS volumes due to weather. The decrease in gas costs was caused by a $362 million or 17% decrease in sales volumes due primarily to weather and $8 million due to the expiration of the GCUA clause in January 2005, offset by $287 million or 11% in higher prices.

The $634 million increase for the year ended December 31, 2005, as compared to 2004, was comprised of increases of $319 million in electric costs and $315 million in gas costs. The increase in electric costs was caused by a $264 million or 8% increase due to higher prices for BGS and NUG purchases and a $67 million increase due to higher BGS volumes, partially offset by a decrease of $12 million due to lower NUG volumes. The increased gas costs were due to a $271 million or 16% increase in gas prices and an $81 million increase in sales volumes due primarily to higher sales to cogenerators. These were offset by a $37 million decrease due to the expiration of the GCUA clause in January 2005.

Operation and Maintenance

The $9 million increase for the year ended December 31, 2006, as compared to 2005, was due primarily to $9 million in increased labor and fringe benefits due to increased wages and Other Postretirement Benefits (OPEB) costs and $7 million in increased bad debt expense. These increases were offset by decreases of $3 million in injuries and damage claims and $2 million in write offs and $2 million in Net Operating Loss (NOL) purchases.

The $68 million increase for the year ended December 31, 2005, as compared to 2004, was due to increased SBC expenses of $27 million ($15 million electric, $12 million gas); $23 million in labor and fringe benefits; $6 million for increased injuries and damages reserves; $4 million for Merger-related expenses; $3 million for higher regulatory commission expenses; $2 million for higher bad debt expenses and $2 million for the purchase of NOL. SBC costs are deferred when incurred and amortized to expense when recovered in revenues.

Depreciation and Amortization

The $67 million increase for the year ended December 31, 2006, as compared to 2005, was comprised of increases of $70 million from the expiration of an excess depreciation credit, $6 million due to amortization of regulatory assets and $3 million due to additional plant in service. These increases were offset by decreases of $5 million due to revised plant depreciation and cost of removal rates, $3 million due to software amortization and $3 million due to the amortization of the Remediation Adjustment Clause (RAC).

The $30 million increase for the year ended December 31, 2005, as compared to 2004, was due primarily to a $33 million increase in the amortization of securitized regulatory assets, a $4 million increase due to additional plant in service and a $4 million increase in the amortization of the RAC. These were offset by an $8 million decrease in software amortization and a $3 million increase in excess depreciation reserve amortization.

Other Income and Deductions

The $10 million increase for the year ended December 31, 2006, as compared to 2005, was primarily due to an $8 million income tax gross-up on contributions in aid of construction (CIAC) in 2006. CIAC are taxable and PSE&G recognizes the gross-up as income when collected. Also included are increases of $1 million of short-term interest income and $1 million in gains on the sale of excess property.

Interest Expense

The $20 million decrease for the year ended December 31, 2005, as compared to 2004, was primarily due to decreases of $22 million due to lower average interest rates and lower amounts of long-term debt outstanding, primarily offset by $5 million in higher short-term debt balances outstanding and higher interest rates.

Income Taxes

The $52 million decrease for the year ended December 31, 2006, as compared to 2005, was primarily due to $55 million in lower pre-tax income offset by $3 million in various flow-through adjustments.

The $11 million decrease for the year ended December 31, 2005, as compared to 2004, was primarily due to decreases of $4 million in prior period adjustments, $3 million in various flow-through benefits and $3 million in lower pre-tax income.

Power

For the year ended December 31, 2006, Power had Net Income of $276 million, an increase of $84 million as compared to the year ended December 31, 2005. The increase primarily resulted from higher BGS contract prices and higher sales volumes in the various power pools, supported by improved nuclear operations and the commencement of commercial operations at Linden in May 2006 and at the Bethlehem Energy Center (BEC) in July 2005 and lower generation costs due to lower pool prices and lower demand under the BGS contract. Power also had lower non-trading mark-to-market losses, which were approximately $1 million, after-tax, in 2006 as compared to $8 million, after-tax, in 2005. Power s increased earnings were partially offset by reduced margins on BGSS, as market prices for natural gas declined from historically high price levels experienced in the second half of 2005 while the cost of gas in inventory was reasonably stable, and lower demand in 2006 due to a warmer winter heating system and customer conservation. Power s earnings were also offset by a $44 million write-down of four gas engine turbines which are planned for sale in 2007, a $30 million after-tax decrease in Income from the NDT Funds and higher Operation and

Maintenance Costs, Depreciation and Amortization and Interest Expense related to operation of the Linden and BEC facilities.

For the year ended December 31, 2005, Power had Net Income of $192 million, a decrease of $116 million as compared to the year ended December 31, 2004. The primary reason for the decrease was the $178 million Loss on Disposal of Waterford and the $16 million Cumulative Effect of a Change in Accounting Principle recorded in 2005. Power s Income from Continuing Operations for the year ended December 31, 2005 was $434 million, an increase of $67 million as compared to 2004. This increase reflected higher pricing and increased sales in the various power pools and new wholesale contracts and reduced Operation and Maintenance costs associated with the outage at Hope Creek in 2004. Marked improvement in Power s nuclear operations provided additional low-cost energy to satisfy Power s contractual obligations and to sell into the market at higher prices. The increases at Power were partially offset by interest and depreciation costs related to facilities in Albany, New York, which commenced operation in July 2005 and Lawrenceburg, Indiana, which commenced operation in June 2004.

The year-over-year detail for these variances for these periods are discussed in more detail below:

	For the Years Ended December 31,			2006 vs 2005		2005 vs 2004	
	2006	**2005**	**2004**	**Increase (Decrease)**	**%**	**Increase (Decrease)**	**%**
		(Millions)				**(Millions)**	
Operating Revenues	$ 6,057	$ 6,027	$ 5,166	$ 30		$ 861	1
Energy Costs	$ 3,955	$ 4,266	$ 3,553	$ (311)	(7)	$ 713	2
Operation and Maintenance	$ 958	$ 939	$ 948	$ 19	2	$ (9)	
Write-Down of Assets	$ 44	$	$	$ 44	N/A	$	N/
Depreciation and Amortization	$ 140	$ 114	$ 98	$ 26	23	$ 16	1
Other Income and Deductions	$ 66	$ 144	$ 117	$ (78)	(54)	$ 27	2
Interest Expense	$ (148)	$ (100)	$ (90)	$ 48	48	$ 10	1
Income Tax Expense	$ (363)	$ (318)	$ (227)	$ 45	14	$ 91	4
Loss from Discontinued Operations, including Loss on Disposal, net of tax	$ (239)	$ (226)	$ (59)	$ 13	6	$ 167	N/

Cumulative Effect of a Change in Accounting Principle, net of tax	$	$	(16)	$	$	16	N/A	$	(16)	N/

Operating Revenues

The $30 million increase for the year ended December 31, 2006 as compared to 2005 was due to increases of $239 million in generation revenues and $27 million in trading revenues, which were partially offset by a decrease of $236 million in gas supply revenues.

The $861 million increase for the year ended December 31, 2005, as compared to 2004, was due to increases of $543 million in generation revenues and $368 million in gas supply revenues, which were partially offset by a decrease of $50 million in trading revenues.

Generation

The $239 million increase in generation revenues for the year ended December 31, 2006, as compared to 2005, was primarily due to an increase of $238 million from higher sales volumes in the various power pools, supported by improved nuclear operations and the commencement of the commercial operations of Linden in May 2006 and BEC in July 2005, partially offset by lower pool prices. Also contributing to the increase was $92 million of higher BGS contract revenues due to higher contract prices which were partly offset by a reduction in load being served under the fixed-price BGS contracts and termination of BGS hourly contracts in May 2006. The increases were partially offset by a decrease of $58 million due to certain wholesale contracts ending in 2005 and early 2006 and $33 million of unrealized losses on asset-backed electric forward contracts.

The $543 million increase in generation revenues for the year ended December 31, 2005, as compared to 2004, was primarily due to higher revenues of $226 million from higher pricing and increased sales in the various power pools supported by improved nuclear capacity, partially offset by reduced load being served under the fixed-priced BGS contracts. Also contributing to the increase were increases of $103 million from new wholesale contracts, $74 million from operations in New York, largely due to the commencement of

BEC s operations, $65 million from RMR revenues, which Power began receiving in 2005 for certain of its generating facilities, and $75 million from increased ancillary services and operating reserves.

Gas Supply

The $236 million decrease in gas supply revenues for the year ended December 31, 2006, as compared to 2005, was primarily due to decreases of $334 million due to lower demand under the BGSS contract in 2006 due to a warmer winter heating season and improved customer conservation in 2006 and a $94 million in decreased prices and gas volumes and pipeline capacity sold to other gas distributors. The decreases were partially offset by an increase of $188 million due to higher prices under the BGSS contract.

The $368 million increase in gas supply revenues for the year ended December 31, 2005, as compared to 2004, was principally due to higher prices under the BGSS contract for gas and pipeline capacity partially offset by lower demand, largely resulting from a warmer winter heating season in 2005 as compared to 2004.

Trading

The $27 million increase in trading revenues for the year ended December 31, 2006, as compared to 2005, was principally due to higher realized gains related to emissions credits.

The $50 million decrease in trading revenues for the year ended December 31, 2005, as compared to 2004, resulted principally from reductions in realized gains related to emission credits.

Operating Expenses

Energy Costs

Energy Costs represent the cost of generation, which includes fuel purchases for generation as well as purchased energy in the market, and gas purchases to meet Power s obligation under its BGSS contract with PSE&G.

The $311 million decrease for the year ended December 31, 2006, as compared to 2005, was primarily due to decreases of $267 million from lower pool prices and lower demand under the BGS contract, $144 million from a reduced volume of gas purchased to satisfy Power s BGSS obligations, somewhat offset by higher gas prices related to inventory for the 2005/2006 winter heating season, and $58 million due to favorable pricing of fuel-related asset-backed transactions in 2006. These decreases were partially offset by $80 million of losses realized on gas hedges in 2006, an increase of $42 million in fuel costs and an increase of $35 million in transmission fees. The increase in fuel costs was largely due to higher volumes of gas purchased to meet increased production by the gas-fired plants, including Linden and BEC, and higher oil prices, partially offset by lower gas prices during 2006 and a lower volume of oil purchases due to reduced running times of certain of the oil-fired plants in 2006.

The $713 million increase for the year ended December 31, 2005, as compared to 2004, was primarily due to increased generation costs, reflecting higher fossil fuel prices and higher prices on an increased volume of purchased power for new contracts and higher prices for gas purchased to satisfy Power s BGSS obligations.

Operation and Maintenance

The $19 million increase for the year ended December 31, 2006, as compared to 2005, was principally due to higher maintenance costs of $60 million related to certain of the fossil plants and scheduled outages at the nuclear units. These increases were partially offset by the absence of a $14 million restructuring charge recorded in 2005 related to Nuclear s workforce realignment plan, a decrease of $10 million in payroll and benefits due to a reduction in employees and a decrease of $14 million in fees paid to Services for information technology and various administrative services.

The $9 million decrease for the year ended December 31, 2005, as compared to 2004, was primarily due to a decrease of $36 million in equipment repair costs related to outages at the nuclear facilities, $9 million of lower real estate taxes, $5 million of lower transmission fees in the power pools, $4 million of lower expenses related to reduced trading activities in 2005 and an $8 million settlement of co- owner billings in 2004 related to Power s jointly-owned facilities. The decreases were substantially offset by an increase of $11 million in pension, postretirement and other employee benefits, a $16 million increase attributable to repairs for outages at the fossil generation plants, the aforementioned $14 million restructuring charge and a $12 million settlement with the U.S. Department of Energy (DOE) in 2004.

Write-Down of Assets

The $44 million write-down of assets recorded in 2006 related to four turbines for which Power has no immediate use and intends to sell. For additional information, see Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

Depreciation and Amortization

The $26 million increase for the year ended December 31, 2006, as compared to 2005, was primarily due to the Linden and BEC plants being placed into service in May 2006 and July 2005, respectively.

The $16 million increase for the year ended December 31, 2005, as compared to 2004, was primarily due to the BEC facility being placed into service and a higher depreciable asset base in 2005 at Nuclear.

Other Income and Deductions

The $78 million decrease for the year ended December 31, 2006, as compared to 2005, was primarily due to decreased net realized income of $29 million and increased realized losses of $19 million related to the NDT Funds. Also contributing to the decrease were charges recorded in 2006 of $14 million for an other-than-temporary impairment of certain NDT Fund securities and $14 million for penalties related to negotiations concerning environmental concerns and an alternate pollution reduction plan for Power s Hudson unit.

The $27 million increase for the year ended December 31, 2006, as compared to 2004, was primarily due to increased realized gains and income of $13 million related to the NDT Funds, lower realized losses of $8 million in 2005 on NDT Funds and a $5 million gain from the sale in September 2005 of four gas turbine generators located in Burlington, New Jersey.

Interest Expense

The $48 million increase for the year ended December 31, 2006, as compared to 2005, was due primarily to lower capitalized interest costs in 2006 related to commencement of operations of the Linden and BEC facilities.

The $10 million increase for the year ended December 31, 2005, as compared to 2004, was due primarily to $8 million of lower capitalized interest costs in 2005 related to commencement of operations of BEC.

Income Taxes

The $45 million increase for the year ended December 31, 2006, as compared to 2005, was primarily due to higher pre-tax income.

The $91 million increase for the year ended December 31, 2005, as compared to 2004, was primarily due to an increase of $63 million in taxes on pre-tax income, the recording in 2005 of $15 million of taxes for the NDT Funds and the reversal in 2004 of $16 million of contingency reserves and other prior period adjustments.

Loss from Discontinued Operations, including Loss on Disposal, net of tax

On December 29, 2006, Power entered into an agreement to sell its Lawrenceburg generation facility for approximately $325 million and recognized an estimated loss on disposal of $208 million, net of tax, in December

2006, for the initial write-down of its carrying amount of Lawrenceburg to its fair value less cost to sell. The transaction is anticipated to close in the second quarter of 2007. Losses from Discontinued Operations of Lawrenceburg, not including the estimated Loss of Disposal, were $31 million, $28 million and $25 million for the years ended December 31, 2006, 2005 and 2004, respectively.

On May 27, 2005, Power reached an agreement to sell its Waterford generation facility for approximately $220 million and recognized an estimated loss on disposal of $177 million, net of tax, for the initial write-down of its carrying amount of Waterford to its fair value less cost to sell. On September 28, 2005, Power completed the sale of Waterford and recognized an additional loss of $1 million. Losses from Discontinued Operations of Waterford, not including the Loss of Disposal, were $20 million and $34 million for the years ended December 31, 2005 and 2004, respectively.

See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes for additional information.

Cumulative Effect of a Change in Accounting Principle

For the year ended December 31, 2005, Power recorded an after-tax loss in the amount of $16 million due to the required recording of a liability for the fair value of asset-retirement costs primarily related to its generation plants under FIN 47, which was adopted in December 2005. See Note 3. Asset Retirement Obligations of the Notes for additional information.

Energy Holdings

For the year ended December 31, 2006, Energy Holdings had Net Income of $275 million, an increase of $58 million as compared to the year ended December 31, 2005. Included in Energy Holdings Net Income for 2006 was a $178 million after-tax loss on the sale of RGE, which was more than offset by the $226 million after-tax gain on disposal of Elcho and Skawina. Strong operations combined with approximately $29 million of after-tax mark-to-market gains on forward gas contracts in 2006 as compared to $3 million of after-tax mark-to-market losses in 2005 at TIE and higher sales volumes at Sociedad Austral de Electricidad S.A. (SAESA) also contributed to the increase. The increases were partially offset by the absence of an after-tax gain of $43 million from the sale of Resources leveraged lease investment in Generation Station Unit 2 (Seminole) in December 2005.

For the year ended December 31, 2005, Energy Holdings had Net Income of $217 million, an increase of $76 million as compared to the year ended December 31, 2004. This increase was primarily due to higher earnings due to improved operations at TIE and in South America and the aforementioned gain on the sale of Seminole in December 2005.

The year-over-year detail for these variances for these periods are discussed in more detail below:

	For the Years Ended December 31,			2006 vs 2005		2005 vs 2004	
	2006	2005	2004	Increase (Decrease)	%	Increase (Decrease)	%
		(Millions)				(Millions)	
Operating Revenues	$ 1,357	$ 1,302	$ 836	$ 55	4	$ 466	56
Energy Costs	$ 739	$ 675	$ 322	$ 64	9	$ 353	N/A
Operation and Maintenance	$ 208	$ 215	$ 171	$ (7)	(3)	$ 44	26
Write-Down of Assets	$ 274	$	$	$ 274	N/A	$	N/A
Depreciation and Amortization	$ 52	$ 46	$ 44	$ 6	13	$ 2	5

Income from Equity Method Investments	$	120	$	124	$	119	$	(4)	(3)	$	5	4
Other Income and Deductions	$	11	$	(8)	$	3	$	19	N/A	$	(11)	N/A
Interest Expense	$	(203)	$	(213)	$	(223)	$	(10)	(5)	$	(10)	(4
Income Tax Benefit (Expense)	$	39	$	(69)	$	(45)	$	108	N/A	$	24	53
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal	$	226	$	18	$	(10)	$	208	N/A	$	28	N/A

The classification of the results of Global s investments on Energy Holdings Consolidated Financial Statements is dependent upon Global s ownership percentage in the underlying investment which determines whether the investment is consolidated into Energy Holdings Consolidated Financial Statements or if it is accounted for under the equity method of accounting. Global owns 100% of TIE, SAESA and Electroandes S.A. (Electroandes) and 85% of Prisma 2000 S.p.A. (Prisma). As a result, the revenues, expenses, assets and liabilities of those investments are reflected on Energy Holdings Consolidated Financial Statements. Global s investments in Chilquinta Energia (Chilquinta), Luz del Sur S.A.A. (LDS), GWF, Kalaeloa Partners L.P. (Kalaeloa) and several other smaller investments are accounted for under the equity method of accounting. Therefore, Energy Holdings only records its share of the net income from these projects as Income from Equity Method Investments on its Consolidated Statements of Operations.

The variances in Operating Revenues, Energy Costs, Operation and Maintenance, Depreciation and Amortization and Income from Equity Method Investments were primarily attributed to Global s increased revenues at TIE in 2006, as compared to same period in 2005, primarily due to unrealized gains on forward contracts and a stronger market and stronger spark spread (the difference between the market price of electricity and the cost of natural gas fuel), the consolidation of Prisma in May 2006, which generated $32 million of revenue, and Global s sale of a 35% interest in Dhofar Power Company S.A.O.C. (Dhofar Power) through a public offering on the Omani Stock Exchange in April 2005 and sale of its remaining interest of 46% in November 2006, receiving net proceeds after-tax of approximately $31 million, the approximate book value of the investment. The variances are also related to favorable foreign currency exchange rates and higher energy sales volumes at SAESA.

Operating Revenues

The increase of $55 million for the year ended December 31, 2006, as compared to 2005, was due to higher revenues at Global of $128 million, which was primarily related to a $79 million increase at TIE due to higher unrealized gains on forward contracts which were slightly offset by a reduction in gas sales. Also contributing to the increase at Global was a $78 million increase at SAESA in Chile due to higher energy sales volumes as well as tariff increases and favorable foreign currency exchange rates, a $24 million increase due to the consolidation of Prisma and $10 million of increased revenue from Electroandes due to volume and price increases. These increases were partly offset by a $37 million decrease due to the absence of a gain from withdrawal from the Eagle Point Cogeneration Partnership in the prior year and the absence of $20 million of revenue due to the deconsolidation of Dhofar Power. Offsetting the increases at Global were lower revenues at Resources of $73 million primarily due to the absence of a $71 million pre-tax gain from the sale of Resources interest in Seminole Generation in December 2005 coupled with the absence of $20 million of leveraged lease income in 2006 due to the Seminole sale, partially offset by a $21 million write-off of a leveraged lease investment with United Airlines in 2005.

The increase of $466 million for the year ended December 31, 2005, as compared to 2004, was due to higher revenues at Global of $406 million, including a $279 million increase related to the consolidation of TIE commencing July 1, 2004 and $136 million due to higher revenues at TIE in the second half of 2005 and a $62 million increase related to SAESA due to higher energy sales volumes offset by a $43 million decrease related to the deconsolidation of Dhofar Power and the absence of a $35 million gain on the sale of Meiya Power Company Limited (MPC) in 2004. Also contributing to the increase were higher revenues at Resources of $60 million primarily due to the $71 million pre-tax gain recognized in 2005 from the sale of its interest in Seminole offset by the absence of an $11 million pre-tax charge recorded due to the termination of the lease investment in the Collins generating facility in 2004.

Energy Costs

The increase of $64 million for the year ended December 31, 2006, as compared to 2005, was primarily due to a $59 million increase at SAESA due to increased volume and higher spot prices for energy and an $8 million increase due to the consolidation of Prisma in May 2006, partially offset by a $5 million decrease related to the deconsolidation of Dhofar Power.

The increase of $353 million for the year ended December 31, 2005, as compared to 2004, was primarily due to a $219 million increase related to the consolidation of TIE commencing July 1, 2004, a $99 million increase in energy costs at TIE in the second half of 2005 and a $44 million increase related to SAESA due to significant increases in Energy Costs, offset by a $13 million decrease related to the deconsolidation of Dhofar Power.

Operation and Maintenance

The decrease of $7 million for the year ended December 31, 2006, as compared to 2005, was primarily due to a reduction of $9 million at Resources mainly due to a reduction of operating lease expense. The decrease is also due to a $4 million reduction in administrative expenses related to lower corporate assessments, wages and benefits, and legal and consulting expense. These decreases are offset by an $8 million increase at Global due to a $17 million increase related to the operations of SAESA, $5 million increase due to the consolidation of Prisma partially offset by a $9 million decrease at TIE and a $4 million decrease from the deconsolidation of Dhofar Power.

The increase of $44 million for the year ended December 31, 2005, as compared to 2004, was primarily due to a $41 million increase related to the consolidation of TIE commencing July 1, 2004 and a $14 million increase related to SAESA offset by a $6 million decrease related to the deconsolidation of Dhofar Power and a $7 million decrease in energy costs at TIE in the second half of 2005.

Write-Down of Assets

The $274 million write-down of assets is primarily related to a $263 million pre-tax loss on Global s sale of its 32% indirect ownership interest in RGE, $4 million pre-tax loss related to the sale of Global s interest in Magellan Capital Holdings Corporation (MCHC), and a $7 million pre-tax loss on the impairment of Global s generation projects in Venezuela. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes.

Depreciation and Amortization

The increase of $6 million for the year ended December 31, 2006, as compared to 2005, was primarily due to a $3 million increase at Resources and a $3 million increase at Global due to a $4 million increase related to the consolidation of Prisma and an increase of $3 million at SAESA, offset by a $4 million decrease resulting from the deconsolidation of Dhofar Power.

The increase of $2 million for the year ended December 31, 2005, as compared to 2004, was primarily due to an $8 million increase related to the consolidation of TIE commencing July 1, 2004 and a $2 million increase related to Resources due to the conversion of the Delta and Northwest leases from leveraged leases to operating leases, offset by a $9 million decrease related to the deconsolidation of Dhofar Power.

Income from Equity Method Investments

The decrease of $4 million for the year ended December 31, 2006, as compared to 2005, was primarily driven by the absence of $12 million of earnings due to the sale of RGE in 2006 partially offset by the absence of foreign currency losses in 2005 from Prisma of $8 million.

The increase of $5 million for the year ended December 31, 2005, as compared to 2004, was primarily due to a $20 million increase due to stronger results in South America (RGE and Chilquinta) offset by an $11 million decrease related to the loss of earnings associated with the sale of Global s equity interest in MPC in December 2004 and a $3 million decrease related to Global s investment in Prisma.

Other Income and Deductions

The increase of $19 million for the year ended December 31, 2006, as compared to 2005, was primarily due to an increase in interest and dividend income of approximately $10 million and lower losses in foreign currency transactions due to favorable currency fluctuations mainly for Prisma operations in Italy.

The decrease of $11 million for the year ended December 31, 2005, as compared to 2004, was primarily due to a loss on early extinguishment of debt of $7 million and foreign currency transaction losses of $9 million primarily on notes receivables from Prisma, partially offset by interest income from PSEG related to inter-company loans.

Interest Expense

The decrease of $10 million for the year ended December 31, 2006, as compared to 2005, was mainly due to a decrease in Energy Holdings debt outstanding and a net decrease of $2 million resulting from the consolidation of Prisma and the deconsolidation of Dhofar Power.

The $10 million decrease for the year ended December 31, 2005, respectively, as compared to 2004, was primarily due an $11 million decrease related to the deconsolidation of Dhofar Power in May 2005 and an $8 million decrease related to Resources due to a reduction in intercompany interest charges offset by a $9 million increase related to the consolidation of TIE commencing on July 1, 2004.

Income Taxes

The decrease of $108 million for the year ended December 31, 2006, as compared to 2005, was primarily attributable to a tax benefit resulting from Global s sale of its 32% indirect ownership interest in RGE and sale of SAESA s 50% interest in Empresa de Energia Rio Negro S.A. (Argentine utility operation).

The $24 million increase for the year ended December 31, 2005, as compared to 2004, was primarily due to the recording of $11 million of U.S. tax associated with repatriation of funds under the American Jobs Creation Act of 2004 (Jobs Act), an increase in the mix of domestic earnings for Global due to improved results at TIE, taxes recognized of $28 million from the sale of Seminole and additional benefits resulting from revisions to Resources lease runs performed in the fourth quarter of 2005. For further information on lease runs, see below in Resources forecast of state taxable income and tax liability over the relevant lease terms. This forecast was embedded in the lease reruns and led to an income tax benefit of $43 million in 2004 to reflect the cumulative benefit of this adjustment. This benefit was largely offset by the tax impact associated with a $31 million decrease in leveraged lease revenue.

Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax

Elcho and Skawina

In 2006, Global sold its interest in two coal-fired plants in Poland, Elcho and Skawina. Proceeds, net of transaction costs, were $476 million, resulting in a gain of $227 million net of tax expense of $142 million. Income (Loss) from Discontinued Operations related to Elcho and Skawina for the years ended December 31, 2006, 2005 and 2004 was $227 million, $18 million and $(10) million, respectively. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments of the Notes for additional information.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of liquidity and capital resources is on a consolidated basis for PSEG, noting the uses and contributions of PSEG s three direct operating subsidiaries, PSE&G, Power and Energy Holdings.

Financing Methodology

PSEG, PSE&G, Power and Energy Holdings

Capital requirements for PSE&G, Power and Energy Holdings are met through liquidity provided by internally generated cash flow and external financings. PSEG expects to be able to fund existing commitments, reduce debt and meet dividend requirements using internally generated cash. PSEG, Power and Energy Holdings from time to time make equity contributions or otherwise provide credit support to their respective direct and indirect subsidiaries to provide for part of their capital and cash requirements, generally relating to long-term investments. PSEG does not intend to contribute additional equity to Energy Holdings.

At times, PSEG utilizes intercompany dividends and intercompany loans (except however, that PSE&G may not, without prior BPU approval, and Fossil, Nuclear and ER&T may not without prior FERC approval make loans to their affiliates) to satisfy various subsidiary or parental needs and efficiently manage short-term cash. Any excess funds are invested in short-term liquid investments.

External funding to meet PSEG s, PSE&G s and Power s needs and a majority portion of the requirements of Energy Holdings consist of corporate finance transactions. The debt incurred is the direct obligation of those respective entities. Some of the proceeds of these debt transactions may be used by the respective obligor to make equity investments in its subsidiaries.

As discussed below, depending on the particular company, external financing may consist of public and private capital market debt and equity transactions, bank revolving credit and term loans, commercial paper and/or project financings. Some of these transactions involve special purpose entities (SPEs), formed in accordance with applicable tax and legal requirements in order to achieve specified financial advantages, such as favorable legal liability treatment. PSEG consolidates SPEs, as applicable, in accordance with FIN No. 46, Consolidation of Variable Interest Entities (VIEs) (FIN 46). See Note 2. Recent Accounting Standards of the Notes.

The availability and cost of external capital is affected by each entity s performance, as well as by the performance of their respective subsidiaries and affiliates. This could include the degree of structural separation between PSEG and its subsidiaries and the potential impact of affiliate ratings on consolidated and unconsolidated credit quality. Additionally, compliance with applicable financial covenants will depend upon future financial position, earnings and net cash flows, as to which no assurances can be given.

Over the next several years, PSEG, PSE&G, Power and Energy Holdings may be required to extinguish or refinance maturing debt and, to the extent there is not sufficient internally generated funds, may incur additional debt and/or provide equity to fund investment activities. Any inability to obtain required additional external capital or to extend or replace maturing debt and/or existing agreements at current levels and reasonable interest rates may adversely affect PSEG s, PSE&G s, Power s and Energy Holdings respective financial condition, results of operations and net cash flows.

From time to time, PSEG, PSE&G, Power and Energy Holdings may repurchase portions of their respective debt securities using funds from operations, asset sales, commercial paper, debt issuances, equity issuances and other sources of funding and may make exchanges of new securities, including common stock, for outstanding securities. Such repurchases may be at variable prices below, at or above prevailing market prices and may be conducted by way of privately negotiated transactions, open-market purchases, tender or exchange offers or other means. PSEG, PSE&G, Power and Energy Holdings may utilize brokers or dealers or effect such repurchases directly. Any such repurchases may be commenced or discontinued at any time without notice.

Energy Holdings

A portion of the financing for Global s investments is normally provided by non-recourse financing transactions. These consist of loans from banks and other lenders that are typically secured by project assets and cash flows. Non-recourse transactions generally impose no material obligation on the parent-level investor to repay any debt incurred by the project borrower. The consequences of permitting a project-level default include the potential for loss of any invested equity by the parent. However, in some cases, certain obligations relating to the investment being financed, including additional equity commitments, may be guaranteed by Global and/or Energy Holdings for their respective subsidiaries. PSEG does not provide guarantees or credit support to Energy Holdings or its subsidiaries.

Operating Cash Flows

PSEG, PSE&G, Power and Energy Holdings

PSEG expects strong cash from operations primarily driven by earnings from Power supported by improved energy margins and capacity markets. Operating cash flows are expected to be sufficient to fund capital expenditures and shareholder dividend payments, with excess cash available to invest in the business, reduce debt and/or repurchase common stock.

PSEG

For the year ended December 31, 2006, PSEG s operating cash flow increased by approximately $959 million from $970 million to $1.9 billion, as compared to 2005, due to net increases from its subsidiaries as discussed below.

For the year ended December 31, 2005, PSEG s operating cash flow decreased by approximately $635 million from $1.6 billion to $970 million, as compared to 2004, primarily due to net decreases at Power for its working capital requirements, discussed below.

PSE&G

PSE&G s operating cash flow increased approximately $115 million from $689 million to $804 million for the year ended December 31, 2006, as compared to 2005, primarily due to a decrease in customer receivables, reflecting lower sales volumes due to a warmer winter heating season and lower gas prices in 2006.

PSE&G s operating cash flow decreased approximately $7 million from $696 million to $689 million for the year ended December 31, 2005, as compared to 2004.

Power

Power s operating cash flow increased approximately $907 million from $136 million to $1 billion for the year ended December 31, 2006, as compared to 2005, due to a significant reduction in margin requirements and fuel inventories, largely resulting from decreases in commodity prices.

Power s operating cash flow decreased approximately $371 million from $507 million to $136 million for the year ended December 31, 2005, as compared to 2004 primarily due to increased margin requirements and an increase in fuel inventory because of significantly increased commodity prices.

Energy Holdings

Energy Holdings operating cash flow decreased approximately $114 million from $273 million to $159 million for the year ended December 31, 2006, as compared to 2005. The decrease was mainly due to taxes paid related to the sale of Elcho, Skawina and RGE in 2006. The proceeds from the these sales are included in Cash Flows from Investing Activities on Energy Holdings Consolidated Statements of Cash Flows.

Energy Holdings operating cash flow decreased approximately $130 million from $403 million to $273 million for the year ended December 31, 2005, as compared to 2004, due primarily to a decrease in Resources cash flows, which was driven by the timing of receipt of tax benefits, and the monetization of the remaining receivables of PETAMC in 2004.

Common Stock Dividends

Dividend payments on common stock for the year ended December 31, 2006 were $2.28 per share and totaled approximately $574 million. Dividend payments on common stock for the year ended December 31, 2005 were $2.24 per share and totaled approximately $541 million. Future dividends declared will be dependent upon PSEG s future earnings, cash flows, financial requirements, alternative investment opportunities and other factors. On January 17, 2007, PSEG announced an increase in its dividend from $0.57 to $0.585 per share for the first quarter of 2007. This quarterly increase reflects an indicated annual dividend rate of $2.34 per share.

Short-Term Liquidity

PSEG, PSE&G, Power and Energy Holdings

In December 2006, PSEG and Power established new credit facilities, which are available for letters of credit and short-term funding, replacing their previous credit facilities. PSEG s new facility also provides liquidity backup for its $1 billion commercial paper program. Also in December 2006, PSE&G amended its $600 million credit facility to update the terms and extend the expiration date to June 2011.

PSEG, PSE&G, Power and Energy Holdings each believe that sufficient liquidity exists to fund their respective short-term cash needs.

As of December 31, 2006, PSEG and its subsidiaries had a total of approximately $3.7 billion of committed credit facilities with approximately $3.3 billion of available liquidity under these facilities. In addition, PSEG and PSE&G have access to certain uncommitted credit facilities. Each of the facilities is restricted to availability and use to the specific companies as listed below. As of December 31, 2006, PSEG has no loans outstanding under its uncommitted facility and PSE&G had $31 million of loans outstanding under its uncommitted facility.

Company	Expiration Date	Total Facility	Primary Purpose	Usage as of December 31, 2006	Available Liquidity as of December 31, 2006
			(Millions)		
PSEG:					
5-year Credit Facility	Dec 2011	$ 1,000	CP Support/Funding/Letters of Credit	$ 354	$ 646
Uncommitted Bilateral Agreement	N/A	$ N/A	Funding	$	$ N/A
PSE&G:					
5-year Credit Facility	June 2011	$ 600	CP Support/Funding/Letters of Credit	$	$ 600
Uncommitted Bilateral Agreement	N/A	N/A	Funding	$ 31	$ N/A
PSEG and Power:(A)					
Bilateral Credit Facility	June 2007	$ 200	Funding/Letters of Credit	$ 19 (C)	$ 181
Power:					
5-year Credit Facility	Dec 2011	$ 1,600	Funding/Letters of Credit	$ 20 (C)	$ 1,580
Bilateral Credit Facility	March 2010	$ 100	Funding/Letters of Credit	$	$ 100
Energy Holdings:					
5-year Credit Facility(B)	June 2010	$ 150	Funding/Letters of Credit	$ 6 (C)	$ 144

(A) PSEG/Power joint and several co-borrower facilities.

(B) Energy Holdings/Global/Resources joint and several co-borrower facility.

(C) These amounts relate to letters of credit outstanding.

Power

As of December 31, 2006, Power had borrowed $54 million from PSEG in the form of an intercompany loan.

During the year ending December 31, 2006, Power s required margin postings for sales contracts entered into in the normal course of business decreased as commodity prices declined. The required margin postings will fluctuate based on volatility in commodity prices. Should commodity prices rise, additional margin calls may be necessary relative to existing power sales contracts. As Power s contract obligations are fulfilled, liquidity requirements are reduced.

In addition, ER&T maintains agreements that require Power, as its guarantor under performance guarantees, to satisfy certain creditworthiness standards. In the event of a deterioration of Power s credit rating to below investment grade, which represents at least a two level downgrade from its current ratings, many of these agreements allow the counterparty to demand that ER&T provide performance assurance, generally in the form of a letter of credit or cash. Providing this support would increase Power s costs of doing business and could restrict the ability of ER&T to manage and optimize Power s asset portfolio. Power believes it has sufficient liquidity to meet any required posting of collateral resulting from a credit rating downgrade. See Note 12. Commitments and Contingent Liabilities of the Notes for further information.

Energy Holdings

Energy Holdings and its subsidiaries had $98 million in cash, including $38 million invested offshore as of December 31, 2006. In addition, as of December 31, 2006, Energy Holdings had an outstanding demand loan receivable from PSEG of $28 million. See External Financings Energy Holdings below for Energy Holdings additional use of its excess cash.

External Financings

PSEG

On September 1, 2006, PSEG began using treasury stock to settle the exercise of stock options. Prior to September 1, 2006, PSEG had purchased shares on the open market to meet the exercise of stock options. As of December 31, 2006, PSEG issued 410,365 shares of its common treasury stock in connection with settling stock options for approximately $15 million.

For the year ended December 31, 2006, PSEG issued approximately 1 million shares of its common stock under its Dividend Reinvestment Program and its Employee Stock Purchase Program for approximately $68 million.

In October 2006, PSEG repaid $49 million of its 6.89% Senior Notes which are due in equal installment payments through 2009.

In February 2006, PSEG redeemed $154 million of its Subordinated Debentures underlying $150 million of Enterprise Capital Trust II, Floating Rate Capital Securities and its common equity investment in the trust.

PSE&G

On June 23, 2006, PSE&G repaid at maturity $175 million of its Floating Rate Series A First and Refunding Mortgage Bonds.

On March 1, 2006, PSE&G repaid at maturity $147 million of its 6.75% Series UU First and Refunding Mortgage Bonds.

In December 2006, PSE&G issued $250 million of 5.70% Secured Medium Term Notes Series D due 2036. The proceeds were used to replace in part the aforementioned matured Floating Rate Series A and 6.75% Series UU First and Refunding Mortgage Bonds.

For the year ended December 31, 2006, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II) repaid approximately $155 million and $8 million, respectively, of their transition bonds.

On January 2, 2007, PSE&G repaid at maturity $113 million of its 6.25% Series WW First and Refunding Mortgage Bonds.

Power

In April 2006, Power repaid at maturity $500 million of its 6.875% Senior Notes.

Energy Holdings

In January 2006, Energy Holdings redeemed all $309 million of its 7.75% Senior Notes due in 2007.

On February 17, 2006, the maturity of the Odessa Ector Power Partners, L.P. (Odessa) debt was extended to December 31, 2009. Interest on the debt is based on a spread (currently 2.25%) above LIBOR. On September 29, 2006, an interest rate swap took effect which converted the floating LIBOR interest rate on approximately 80% of Odessa s debt to a fixed rate of 5.4275% through December 31, 2009.

On October 23, 2006, Energy Holdings redeemed $300 million of its $507 million outstanding 8.625% Senior Notes due in 2008.

During 2006, Energy Holdings made cash distributions to PSEG totaling $520 million in the form of returns of capital.

Also during 2006, Energy Holdings subsidiaries repaid approximately $51 million of non-recourse debt, of which $43 million primarily related to SAESA and TIE, $6 million by Resources and $2 million by EGDC.

Debt Covenants

PSEG, PSE&G, Power and Energy Holdings

PSEG s, PSE&G s, Power s and Energy Holdings respective credit agreements may contain maximum debt to equity ratios, minimum cash flow tests and other restrictive covenants and conditions to borrowing. Compliance with applicable financial covenants will depend upon the respective future financial position, level of earnings and cash flows of PSEG, PSE&G, Power and Energy Holdings, as to which no assurances can be given. The ratios presented below are for the benefit of the investors of the related securities to which the covenants apply. They are not intended as financial performance or liquidity measures. The debt underlying the preferred securities of PSEG, which is presented in Long-Term Debt in accordance with FIN 46, is not included as debt when calculating these ratios, as provided for in the various credit agreements.

Energy Holdings credit agreement also contains customary provisions under which the lender could refuse to advance loans in the event of a material adverse change in the borrower s business or financial condition.

PSEG

Financial covenants contained in PSEG s credit facilities include a ratio of debt (excluding non-recourse project financings, securitization debt and debt underlying preferred securities and including commercial paper and loans, certain letters of credit not related to collateral postings for commodity/energy contracts and similar instruments) to total capitalization (including preferred securities outstanding and excluding any impacts for Accumulated Other Comprehensive Income adjustments related to marking energy contracts to market and equity reductions from the funded status of pensions or benefit plans associated with SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans) covenant. This covenant requires that such ratio not be more than 70.0%. As of December 31, 2006, PSEG s ratio of debt to capitalization (as defined above) was 51.6%.

PSE&G

Financial covenants contained in PSE&G s credit facilities include a ratio of long-term debt (excluding securitization debt, long-term debt maturing within one year and short-term debt) to total capitalization covenant. This covenant requires that such ratio will not be more than 65.0%. As of December 31, 2006, PSE&G s ratio of long-term debt to total capitalization (as defined above) was 48.5%.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2006, PSE&G s Mortgage coverage ratio was 4.1 to 1 and the Mortgage would permit up to approximately $2.1 billion aggregate principal amount of new Mortgage Bonds to be issued against previous additions and improvements.

Power

Financial covenants contained in Power s credit facility include a ratio of debt to total capitalization covenant. The Power ratio is the same debt to total capitalization calculation as set forth above for PSEG except common equity is adjusted for the $986 million Basis Adjustment (see Consolidated Balance Sheets). This covenant requires that such ratio will not exceed 65.0%. As of December 31, 2006, Power s ratio of debt to total capitalization (as defined above) was 38.4%.

Energy Holdings

Energy Holdings bank revolving credit agreement has a covenant requiring the ratio of Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) to fixed charges to be greater than or equal to 1.75. As of December 31, 2006, Energy Holdings coverage of this covenant was 3.53. Additionally, Energy Holdings must maintain a ratio of net debt (recourse debt offset by funds loaned to PSEG) to EBITDA of less than 5.25. As of December 31, 2006, Energy Holdings ratio under this covenant was 2.59. Energy Holdings is a co-borrower under this facility with Global and Resources, which are joint and several obligors. The terms of the agreement include a pledge of Energy Holdings membership interest in Global, restrictions on the use of proceeds related to material sales of assets and the satisfaction of certain financial covenants. Net cash proceeds from asset sales in excess of 5% of total assets of Energy Holdings during any 12-month period must be used to repay any outstanding amounts under the credit agreement. Net cash proceeds from asset sales during any 12-month period in excess of 10% of total assets must be retained by Energy Holdings or used to repay the debt of Energy Holdings, Global or Resources.

Energy Holdings indenture with respect to its senior notes does not permit liens securing indebtedness in excess of 10% of consolidated net tangible assets as calculated under the terms of the indenture. The terms of Energy Holdings Senior Notes allow the holders to demand repayment if a transaction or series of related transactions causes the assets of Resources to be reduced by 20% or more and as a direct result there is a downgrade of ratings.

Cross Default Provisions

PSEG, PSE&G, Power and Energy Holdings

The PSEG bank credit agreement contains default provisions under which a default by it in an aggregate amount of $50 million or greater would result in the potential acceleration of payment under this agreement. Under certain conditions, a default by PSE&G or Power in an aggregate amount of $50 million or greater would also result in potential acceleration of payment under this agreement. PSEG has removed Energy Holdings from all cross default provisions.

PSEG s bank credit agreement and note purchase agreements related to private placement of debt (collectively, Credit Agreements) contain cross default provisions under which certain payment defaults by PSE&G or Power, certain bankruptcy events relating to PSE&G or Power, the failure by PSE&G or Power to satisfy certain final judgments or the occurrence of certain events of default under the financing agreements of PSE&G or Power, would each constitute an event of default under the PSEG Credit Agreements. Under the note purchase agreements, it is also an event of default if PSE&G or Power ceases to be wholly-owned by PSEG. Under the bank credit agreement, both PSE&G and Power would have to cease to be wholly-owned by PSEG before an event of default would occur.

PSE&G

PSE&G s Mortgage has no cross defaults. The PSE&G Medium-Term Note Indenture has a cross default to the PSE&G Mortgage. The PSE&G credit agreement has a provision under which a default by PSE&G in the aggregate of $50 million or greater would result in an event of default and the potential acceleration of payment under that agreement.

Power

The Power Senior Debt Indenture contains a default provision under which a default by Power, Nuclear, Fossil or ER&T in an aggregate amount of $50 million or greater would result in an event of default and the potential acceleration of payment under the indenture. There are no cross defaults within Power s indenture from PSEG, Energy Holdings or PSE&G.

The Power credit agreement also has a provision under which a default by Power, Nuclear, Fossil or ER&T in an aggregate amount of $50 million or greater would result in an event of default and the potential acceleration of payment under that agreement.

Energy Holdings

Energy Holdings credit agreement and Senior Note Indenture contain default provisions under which a default by it, Resources or Global in an aggregate amount of $25 million or greater would result in an event of default and the potential acceleration of payment under that agreement or the Indenture.

Ratings Triggers

PSEG, PSE&G, Power and Energy Holdings

The debt indentures and credit agreements of PSEG, PSE&G, Power and Energy Holdings do not contain any material ratings triggers that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements.

PSE&G

In accordance with the BPU approved requirements under the BGS contracts that PSE&G enters into with suppliers, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, PSE&G would be required to file with the BPU a plan to assure continued payment for the BGS requirements of its customers.

PSE&G is the servicer for the bonds issued by Transition Funding and Transition Funding II. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. Currently, cash is remitted monthly.

Power

In connection with the management and optimization of Power s asset portfolio, ER&T maintains underlying agreements that require Power, as its guarantor under performance guarantees, to satisfy certain creditworthiness standards. In the event of a deterioration of Power s credit rating to below an investment grade rating, many of these agreements allow the counterparty to demand that ER&T provide performance assurance, generally in the form of a letter of credit or cash. As of December 31, 2006, if Power were to lose its investment grade rating and assuming all the counterparties to agreements in which ER&T is out-of-the-money were contractually entitled to demand, and demanded, performance assurance, ER&T could be required to post collateral in an amount equal to approximately $578 million. See Note 12. Commitments and Contingent Liabilities of the Notes.

Credit Ratings

PSEG, PSE&G, Power and Energy Holdings

Following the termination of the Merger Agreement in September 2006, credit ratings remained unchanged as shown in the table below. Standard & Poor s (S&P) affirmed its BBB corporate credit rating for PSEG, Power, and PSE&G. S&P revised its outlook from watch developing to negative. Moody s Investors Service (Moody s) affirmed its credit ratings for PSEG and PSE&G while revising the outlooks from stable to negative. The ratings and outlooks for Power and Energy Holdings were unchanged by Moody s. Fitch Ratings (Fitch) announced there would be no immediate impact on ratings and outlooks for PSEG and its subsidiaries. At that time, the agencies noted that the ratings below were predicated on continued improvement in financial metrics, specifically operating cash flows and ongoing deleveraging, as well as continued strong operating performance from Power s generating units and reasonable outcomes to PSE&G s pending electric and gas rate cases.

If the rating agencies lower or withdraw the credit ratings, such revisions may adversely affect the market price of PSEG s, PSE&G s, Power s and Energy Holdings securities and serve to materially increase those companies cost of capital and limit their access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances so warrant. Each rating given by an agency should be evaluated independently of the other agencies ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

	Moody s (A)	**S&P (B)**	**Fitch (C)**
PSEG:			
Outlook	**Neg**	**Neg**	**Pos**
Preferred Securities	Baa3	BB+	BBB
Commercial Paper	P2	A3	F2
Senior Unsecured Debt	Baa2	BBB	BBB
PSE&G:			
Outlook	**Neg**	**Neg**	**Stable**
Mortgage Bonds	A3	A	A
Preferred Securities	Baa3	BB+	BBB+
Commercial Paper	P2	A3	F2
Power:			

Outlook	**Stable**	**Neg**	**Pos**
Senior Notes	Baa1	BBB	BBB
Energy Holdings:			
Outlook	**Neg**	**Neg**	**Neg**
Senior Notes	Ba3	BB	BB

(A) Moody s ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities. /I 8iuok 0p

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from

AAA
(highest)
to D
(lowest)
for
long-term
securities
and F1
(highest)
to D
(lowest)
for
short-term
securities.

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Other Comprehensive Income

PSEG, Power and Energy Holdings

For the year ended December 31, 2006, PSEG, PSE&G, Power and Energy Holdings had Other Comprehensive Income of $706 million, $5 million, $483 million and $217 million, respectively, due primarily to a reduction in the net unrealized losses on derivatives accounted for as hedges in accordance with SFAS 133 at Power and foreign currency translation adjustments at Energy Holdings.

During the year ended December 31, 2006, Power s Accumulated Other Comprehensive Loss decreased from $487 million to $177 million. The primary cause was a decrease of approximately $310 million related to energy and related contracts that qualify for hedge accounting that were entered into by Power in the normal course of business. During the year ended December 31, 2006, the decrease in gas and electric prices resulted in a reduction in unrealized losses on many of those contracts, which are recorded in Accumulated Other Comprehensive Loss. This decrease was partially offset by a $173 million adjustment recorded at Power in connection with the adoption of SFAS 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158).

As of December 31, 2006, Energy Holdings had Accumulated Other Comprehensive Income of $103 million. The primary reasons for the improvement, as compared to the Accumulated Other Comprehensive Loss of $110 million as of December 31, 2005, were the realization of losses on Brazilian currency as a result of the sale of RGE and the unwinding of an interest rate swap due to the sale of Global s facilities in Poland.

CAPITAL REQUIREMENTS

PSEG, PSE&G, Power and Energy Holdings

It is expected that the majority of each subsidiary s capital requirements over the next five years will come from internally generated funds. Projected construction and investment expenditures, excluding nuclear fuel purchases, for PSEG s subsidiaries for the next five years are presented in the table below. These amounts are subject to change, based on various factors.

	2007	2008	2009	2010	2011
			(Millions)		
PSE&G:					
Facility Support	$ 41	$ 77	$ 76	$ 45	$ 48
Environmental/Regulatory	44	30	31	28	28
Facility Replacement	173	175	178	165	179
System Reinforcement	183	183	185	165	161
New Business	164	163	161	157	159
Total PSE&G	605	628	631	560	575
Power:					
Hudson Environmental	68	143	229	263	8
Mercer Environmental	126	132	110	83	
Other Non-Recurring	264	220	64	51	45
Recurring	126	131	113	130	145
Total Power	584	626	516	527	198
Energy Holdings	37	31	40	30	31
Other	35	28	24	24	22
Total PSEG	$ 1,261	$ 1,313	$ 1,211	$ 1,141	$ 826

PSE&G

In 2006, PSE&G made approximately $528 million of capital expenditures, primarily for reliability of transmission and distribution systems. The $528 million does not include approximately $33 million spent on cost of removal. PSE&G s projections for future capital expenditures include additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. The current projections do not include investments required as a result of PJM s approval of the Regional Transmission Expansion Plan (RTEP) in December 2006. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments.

Power

In 2006, Power made approximately $325 million of capital expenditures (excluding $93 million for nuclear fuel), primarily related to installation of emissions control equipment at the Bridgeport Harbor and Mercer stations, completion of construction at the Linden station, in New Jersey and various other projects at Nuclear and Fossil. The projections above include estimates for Hudson and Mercer related to the agreement reached with the EPA and the NJDEP. They do not include the costs, if any, associated with cooling towers for Salem, if required. For additional discussion of the potential costs related Hudson, Mercer and Salem, see Note 12. Commitments and Contingent Liabilities of Notes.

Energy Holdings

In 2006, Energy Holdings incurred approximately $64 million of capital expenditures, primarily related to upgrades and expansion of SAESA s transmission and distribution systems.

Energy Holdings capital needs in 2007 will be limited to fulfilling existing contractual and potential contingent commitments. The balance of the forecasted expenditures relates to capital requirements of consolidated subsidiaries, which will primarily be financed from internally generated cash flow within the projects and from local sources on a non-recourse basis or limited discretionary investments by Energy Holdings. Such capital requirements include organic growth in SAESA s service territory and other capital improvements at Global s consolidated subsidiaries.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects PSEG s and its subsidiaries contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. The table below does not reflect any anticipated cash payments for pension obligations. The table also does not reflect debt maturities of Energy Holdings non-consolidated investments. If those obligations were not able to be refinanced by the project, Energy Holdings may elect to make additional contributions in these investments. For additional information, see Note 10. Schedule of Consolidated Debt of the Notes.

Contractual Cash Obligations	Total Amount Committed	Less Than 1 year	2-3 years	4-5 years	Over 5 years
			(Millions)		
Short-Term Debt Maturities					
PSEG	$ 353	$ 353	$	$	$
PSE&G	31	31			
Long-Term Debt Maturities					
Recourse Debt Maturities					
PSEG(A)	1,376	523	673		180
PSE&G	3,116	113	310		2,693
Transition Funding (PSE&G)	1,784	161	347	381	895
Transition Funding II (PSE&G)	95	10	20	21	44
Power	2,818		250	800	1,768
Energy Holdings	1,149		607	542	
Non-Recourse Project Financing					
Energy Holdings	881	42	467	181	191
Interest on Recourse Debt					
PSEG	96	45	51		
PSE&G	2,477	165	313	295	1,704
Transition Funding (PSE&G)	596	114	196	150	136
Transition Funding II (PSE&G)	20	4	7	5	4
Power	1,917	192	379	334	1,012
Energy Holdings	250	56	100	35	59
Interest on Debt Supporting Trust Preferred Securities					
PSEG	41	41			
Interest on Non-Recourse Project Financing					
Energy Holdings	355	104	181	70	
Capital Lease Obligations					
PSEG	73	8	14	14	37

Power	15	2	3	2	8
Energy Holdings	57	12	24	12	9
Operating Leases					
PSE&G	9	3	2	3	1
Energy Holdings	6	3	2	1	
Energy-Related Purchase Commitments					
Power	2,496	714	943	451	388
Energy Holdings	64	64			
Total Contractual Cash Obligations	$ 20,075	$ 2,760	$ 4,889	$ 3,297	$ 9,129
Standby Letters of Credit					
Power	$ 78	$ 78	$	$	$
Energy Holdings	6	2	4		
Guarantees and Equity Commitments					
Energy Holdings	71	21	50		
Total Commercial Commitments	$ 155	$ 101	$ 54	$	$

(A) Includes debt supporting trust preferred securities of $660 million.

See Note 12. Commitments and Contingent Liabilities of the Notes for a discussion of contractual commitments for a variety of services for which annual amounts are not quantifiable.

OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy trading activities. See Note 12. Commitments and Contingent Liabilities of the Notes for further discussion.

PSEG and Energy Holdings

Global has certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States (GAAP). Accordingly, amounts recorded on the Consolidated Balance Sheets for such investments represent Global s equity investment, which is increased for Global s pro-rata share of earnings less any dividend distribution from such investments. The companies in which Global invests that are accounted for under the equity method have an aggregate $878 million of debt on their combined, consolidated financial statements. PSEG s pro-rata share of such debt is $414 million. This debt is non-recourse to PSEG, Energy Holdings and Global. PSEG is generally not required to support the debt service obligations of these companies. However, default with respect to this non-recourse debt could result in a loss of invested equity.

Resources has investments in leveraged leases that are accounted for in accordance with SFAS No. 13, Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on Energy Holdings Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secure the loan. As a lessor, Resources has ownership rights to the property and rents the property to the lessees for use in their business operation. As of December 31, 2006, Resources equity investment in leased assets was approximately $924 million, net of deferred taxes of approximately $1.9 billion. For additional information, see Note 8. Long-Term Investments of the Notes.

In the event that collectibility of the minimum lease payments to be received by the lessor is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Resources may deem that a lessee has a high probability of defaulting on the lease obligation, and would reclassify the lease from a leveraged lease to an operating lease and would consider the need to record an impairment of its investment. Should Resources ever directly assume a debt obligation, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

Energy Holdings has guaranteed certain obligations of its subsidiaries or affiliates related to certain projects. See Note 12. Commitments and Contingent Liabilities of the Notes for additional information.

CRITICAL ACCOUNTING ESTIMATES

PSEG, PSE&G, Power and Energy Holdings

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. The managements of PSEG, PSE&G, Power and Energy Holdings have each determined that the following estimates are considered critical to the application of rules that relate to their respective businesses.

Accounting for Pensions

PSEG, PSE&G, Power and Energy Holdings account for pensions under SFAS No. 87, Employers Accounting for Pensions (SFAS 87). Pension costs under SFAS 87 are calculated using various economic and demographic assumptions. Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns. In 2006, PSEG and its subsidiaries recorded pension expense of $97 million, compared to $109 million in 2005 and $102 million in 2004. Additionally, in 2006, PSEG and its respective subsidiaries contributed cash of approximately $50 million, compared to cash contributions of $155 million in 2005 and $96 million in 2004.

PSEG s discount rate assumption, which is determined annually, is based on the rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. The discount rate used to calculate pension obligations is determined as of December 31 each year, PSEG s SFAS 87 measurement date. The discount rate used to determine year-end obligations is also used to develop the following year s net periodic pension cost. The discount rates used in PSEG s 2005 and 2006 net periodic pension costs were 6.00% and 5.75%, respectively. PSEG s 2007 net periodic pension cost was developed using a discount rate of 6.00%.

PSEG s expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class using input from PSEG s actuary and investment advisors, as well as long-term inflation assumptions. For 2005 and 2006, PSEG assumed a rate of return of 8.75% on PSEG s pension plan assets. For 2007, PSEG will continue the rate of return assumption of 8.75%.

Based on the above assumptions, PSEG has estimated net period pension costs of approximately $43 million and contributions of up to approximately $66 million in 2007. As part of the business planning process, PSEG has modeled its future costs assuming an 8.75% rate of return and a 6.0% discount rate for 2008 and beyond. Actual future pension expense and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to PSEG s projected benefit obligation and accumulated benefit obligation (ABO) and various other factors related to the populations participating in PSEG s pension plans.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Actuarial Assumption	**Current**	**Change/ (Decrease)**	**As of December 31, 2006 Impact on Pension Benefit Obligation**	**Increase to Pension Expense in 2007**
			(Millions)	
Discount Rate	6.00 %	(1.00 %)	$ 555	$ 52
Rate of Return on Plan Assets	8.75 %	(1.00 %)	$	$ 33

Accounting for Deferred Taxes

PSEG, PSE&G, Power and Energy Holdings provide for income taxes based on the liability method required by SFAS No. 109, Accounting for Income Taxes (SFAS 109). Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, as well as net operating loss and credit carryforwards.

PSEG, PSE&G, Power and Energy Holdings evaluate the need for a valuation allowance against their respective deferred tax assets based on the likelihood of expected future taxable income. PSEG, PSE&G, Power and Energy Holdings do not believe a valuation allowance is necessary; however, if the expected level of future taxable income changes or certain tax planning strategies become unavailable, PSEG, PSE&G, Power and Energy Holdings would record a valuation allowance through income tax expense in the period the valuation allowance is deemed necessary.

Resources and Global s ability to realize their deferred tax assets are dependent on PSEG s subsidiaries ability to generate ordinary income and capital gains.

Hedge and Mark-to-Market (MTM) Accounting

SFAS 133 requires an entity to recognize the fair value of derivative instruments held as assets or liabilities on the balance sheet. SFAS 133 applies to all derivative instruments held by PSEG, PSE&G, Power and Energy Holdings. The fair value of most derivative instruments is determined by reference to quoted market prices, listed contracts, or quotations from brokers. Some of these derivative contracts are long term and rely on forward price quotations over the entire duration of the derivative contracts.

In the absence of the pricing sources listed above, for a small number of contracts, PSEG and its subsidiary companies utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value. Because the determination of fair value using such models is subject to significant assumptions and estimates, PSEG and its subsidiary companies developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of value to record in the financial statements.

PSEG and its subsidiaries have entered into various derivative instruments in order to hedge exposure to commodity price risk, interest rate risk and foreign currency risk. Many such instruments have been designated as cash flow hedges. For a cash flow hedge, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract or business condition the derivative instrument is intended to hedge. This is known as the measure of derivative effectiveness. In accordance with SFAS 133, the effective portion of the change in the fair value of a derivative instrument designated as a cash flow hedge is reported in Accumulated Other Comprehensive Loss, net of tax, or as a Regulatory Asset (Liability). Amounts in Accumulated Other Comprehensive Loss are ultimately recognized in earnings when the related hedged forecasted transaction occurs. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Loss. The changes in the fair value of the ineffective portions of derivative instrument designated as cash flow hedges are recorded in earnings.

For Power s and Holdings wholesale energy businesses, many of the forward sale, forward purchase and other option contracts are derivative instruments that hedge commodity price risk, but for which the businesses are not able to apply the hedge accounting guidance in SFAS 133. The changes in value of such derivative contracts are marked to market through earnings as commodity prices fluctuate. As a result, the earnings of PSEG, Power and Holdings may experience significant fluctuations depending on the volatility of commodity prices.

For Power s energy trading activities, all changes in the fair value of energy trading derivative contracts are recorded in earnings.

For additional information regarding Derivative Financial Instruments, see Note 11. Financial Risk Management Activities of the Notes.

PSE&G

Unbilled Revenues

Electric and gas revenues are recorded based on services rendered to customers during each accounting period. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. Unbilled usage is calculated in two steps. The initial step is to apply a base usage per day to the number of unbilled days in the period. The second step estimates seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms. The resulting usage is priced at current rate levels and recorded as revenue. A calculation of the associated energy cost for the unbilled usage is recorded as well. Each month the prior month s unbilled amounts are reversed and the current month s amounts are accrued. Using benchmarks other than those used in this calculation could have a material effect on the amounts accrued in a reporting period. The resulting revenue and expense reflect the service rendered in the calendar month.

PSE&G

SFAS No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71)

PSE&G prepares its Consolidated Financial Statements in accordance with the provisions of SFAS 71, which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a regulatory asset) or recognize obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs, which will be amortized over various future periods. To the extent that collection of such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or PSE&G s competitive position, the associated regulatory asset or liability is charged or credited to income. See Note 5. Regulatory Matters of the Notes for additional information related to these and other regulatory issues.

Power

NDT Funds

Power accounts for the assets in the NDT Funds under SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS 115). The assets in the NDT Funds are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Loss unless securities with such unrealized losses are deemed to be other-than-temporarily-impaired. Realized gains, losses and dividend and interest income are recorded on Power s and PSEG s Statements of Operations under Other Income and Other Deductions. Unrealized losses that are deemed to be other than temporarily impaired, as defined under SFAS 115, and related interpretive guidance, are charged against earnings rather than Accumulated Other Comprehensive Loss.

Power and Energy Holdings

Accounting for Goodwill

Power and Energy Holdings evaluate their respective goodwill for impairment at least annually or when indications of impairment exist. An impairment may exist when the carrying amount of goodwill exceeds its implied fair value.

Accounting estimates related to goodwill fair value are highly susceptible to change from period to period because they require management to make cash flow assumptions about future sales, operating costs, economic conditions and discount rates over an indefinite life. The impact of recognizing an impairment could have a material impact on financial position and results of operations.

Power and Energy Holdings perform annual goodwill impairment tests and continuously monitor the business environment in which they operate for any impairment issues that may arise. As indicated above, certain assumptions are used to arrive at a fair value for goodwill testing. Such assumptions are consistently employed and include, but are not limited to, free cash flow projections, interest rates, tariff adjustments, economic conditions prevalent in the geographic regions in which Power and Energy Holdings do business, local spot market prices for energy, foreign exchange rates and the credit worthiness of customers. If an adverse event were to occur, such an event could materially change the assumptions used to value goodwill and could result in impairments of goodwill.

PSEG and Energy Holdings

Foreign Currency Translation

Energy Holdings financial statements are prepared using the U.S. Dollar as the reporting currency. In accordance with SFAS No. 52, Foreign Currency Translation , for foreign operations whose functional currency is deemed to be the local (foreign) currency, asset and liability accounts are translated into U.S. Dollars at current exchange rates and revenues and expenses are translated at average exchange rates prevailing during the period. Translation gains and losses (net of applicable deferred taxes) are not included in determining Net Income but are reported in Other Comprehensive Income. Gains and losses on transactions denominated in a currency other than the functional currency are included in the results of operations as incurred.

The determination of an entity s functional currency requires management s judgment. It is based on an assessment of the primary currency in which transactions in the local environment are conducted, and whether the local currency can be relied upon as a stable currency in which to conduct business. As economic and business conditions change, Energy Holdings is required to reassess the economic environment and determine the appropriate functional currency. The impact of foreign currency accounting could have a material adverse impact on Energy Holdings results of operations.

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ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

PSEG, PSE&G, Power and Energy Holdings

The market risk inherent in PSEG s, PSE&G s, Power s and Energy Holdings market-risk sensitive instruments and positions is the potential loss arising from adverse changes in foreign currency exchange rates, commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements (Notes). It is the policy of each entity to use derivatives to manage risk consistent with its respective business plans and prudent practices. PSEG, PSE&G, Power and Energy Holdings have a Risk Management Committee (RMC) comprised of executive officers who utilize an independent risk oversight function to ensure compliance with corporate policies and prudent risk management practices.

Additionally, PSEG, PSE&G, Power and Energy Holdings are exposed to counterparty credit losses in the event of non-performance or non-payment. PSEG has a credit management process, which is used to assess, monitor and mitigate counterparty exposure for PSEG and its subsidiaries. In the event of non- performance or non-payment by a major counterparty, there may be a material adverse impact on PSEG and its subsidiaries financial condition, results of operations or net cash flows.

Foreign Exchange Rate Risk

Energy Holdings

Global is exposed to foreign currency risk and other foreign operations risk that arise from investments in foreign subsidiaries and affiliates. Primarily, Global is impacted by changes in the U.S. Dollar to Peruvian Nuevo Sol and the Chilean Peso exchange rates and to a much lesser extent, the Euro. Whenever possible, these subsidiaries and affiliates have attempted to limit potential foreign exchange impacts by entering into revenue contracts that adjust to changes in foreign exchange rates. Global also uses foreign currency forward, swap and option agreements to manage risk related to certain foreign currency transactions, when appropriate.

Global s investment balances are also impacted by foreign currency changes through translation adjustments. Foreign currency has strengthened on a net basis since Global s acquisitions and investments in Chile and Peru. A foreign currency fluctuation of 10% in such foreign currencies would result in an aggregate change in Accumulated Other Comprehensive Income of $92 million. As of December 31, 2006, Energy Holdings net gain in Accumulated Other Comprehensive Income from currency fluctuations was approximately $111 million.

Commodity Contracts

PSEG and Power

The availability and price of energy commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, Power enters into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with demand obligations help reduce risk and optimize the value of owned electric generation capacity.

Normal Operations and Hedging Activities

Power enters into physical contracts, as well as financial contracts, including forwards, futures, swaps and options designed to reduce risk associated with volatile commodity prices. Commodity price risk is associated with market price movements resulting from market generation demand, changes in fuel costs and various other factors.

Under SFAS 133, changes in the fair value of qualifying cash flow hedge transactions are recorded in Accumulated Other Comprehensive Loss, and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet hedge criteria under SFAS 133 and the ineffective portion of hedge contracts are recognized in earnings currently. Additionally, changes in the fair value attributable to fair value hedges are similarly recognized in earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption under SFAS 133 and are accounted for upon settlement.

Trading

Power maintains a strategy of entering into trading positions to optimize the value of its portfolio of generation assets, gas supply contracts and its electric and gas supply obligations. Power engages in physical and financial transactions in the electricity wholesale markets and executes an overall risk management strategy to mitigate the effects of adverse movements in the fuel and electricity markets. In addition, Power has non-asset based trading activities, which have significantly decreased. These contracts also involve financial transactions including swaps, options and futures. These activities are marked to market in accordance with SFAS 133 with gains and losses recognized in earnings.

Value-at-Risk (VaR) Models

Power

Power uses VaR models to assess the market risk of its commodity businesses. The portfolio VaR model for Power includes its owned generation and physical contracts, as well as fixed price sales requirements, load requirements and financial derivative instruments. VaR represents the potential gains or losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. Power estimates VaR across its commodity businesses.

Power manages its exposure at the portfolio level. Its portfolio consists of owned generation, load-serving contracts (both gas and electric), fuel supply contracts and energy derivatives designed to manage the risk around generation and load. While Power manages its risk at the portfolio level, it also monitors separately the risk of its trading activities and its hedges. Non-trading MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM derivatives that are not hedges are included in the trading VaR.

The VaR models used by Power are variance/covariance models adjusted for the delta of positions with a 95% one-tailed confidence level and a one-day holding period for the MTM trading and non- trading activities and a 95% one-tailed confidence level with a one-week holding period for the portfolio VaR. The models assume no new positions throughout the holding periods, whereas Power actively manages its portfolio.

Reduced trading activities by Power during 2006 have resulted in less trading risk. As of December 31, 2006, trading VaR was immaterial. As of December 31, 2005, trading VaR was approximately $1 million.

For the Year Ended December 31, 2006	**Trading VaR**	**Non-Trading MTM VaR**
	(Millions)	
95% Confidence Level, One-Day Holding Period, One-Tailed:		
Period End	$ *	$ 38
Average for the Period	$ *	$ 46
High	$ *	$ 55
Low	$ *	$ 38
99% Confidence Level, One-Day Holding Period, Two-Tailed:		
Period End	$ *	$ 59
Average for the Period	$ *	$ 73

High	$	*	$	87
Low	$	*	$	59

* less than $1 million

Interest Rates

PSEG, PSE&G, Power and Energy Holdings

PSEG, PSE&G, Power and Energy Holdings are subject to the risk of fluctuating interest rates in the normal course of business. It is the policy of PSEG, PSE&G, Power and Energy Holdings to manage interest rate risk through the use of fixed and floating rate debt, interest rate swaps and interest rate lock agreements. PSEG, PSE&G, Power and Energy Holdings manage their respective interest rate exposures by maintaining a targeted ratio of fixed and floating rate debt. As of December 31, 2006, a hypothetical 10% change in market interest rates would result in a $7 million, $3 million, $1 million and an insignificant change (less than $500 thousand) in annual interest costs related to debt at PSEG, PSE&G, Power and Energy Holdings, respectively. In addition, as of December 31, 2006, a hypothetical 10% change in market interest rates would result in a $7 million, $77 million, $105 million and $32 million change in the fair value of the debt of PSEG, PSE&G, Power and Energy Holdings, respectively.

Debt and Equity Securities

PSEG, PSE&G, Power and Energy Holdings

PSEG has approximately $3.4 billion invested in its pension plans. Although fluctuations in market prices of securities within this portfolio do not directly affect PSEG s earnings in the current period, changes in the value of these investments could affect PSEG s future contributions to these plans, its financial position if its ABO under its pension plans exceeds the fair value of its pension funds and future earnings as PSEG could be required to adjust pension expense and its assumed rate of return.

Power

Power s NDT Funds are comprised of both fixed income and equity securities totaling $1.3 billion as of December 31, 2006. The fair value of equity securities is determined independently each month by the Trustee. As of December 31, 2006, the portfolio was comprised of approximately $785 million of equity securities and approximately $471 million in fixed income securities. The fair market value of the assets in the NDT Funds will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2006, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Funds by approximately $79 million.

Power uses duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Funds is the Lehman Brothers Aggregate Bond Index, which currently has duration of 4.46 years and a yield of 5.34%. The portfolio s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2006, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $7.8 million.

Credit Risk

PSEG, PSE&G, Power and Energy Holdings

Credit risk relates to the risk of loss that PSEG, PSE&G, Power and Energy Holdings would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG, PSE&G, Power and Energy Holdings have established credit policies that they believe significantly minimize credit risk. These policies include an evaluation of potential counterparties financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which may allow for the netting of positive and negative exposures associated with a single counterparty.

PSE&G

BGS suppliers expose PSE&G to credit losses in the event of non-performance or non-payment upon a default of the BGS supplier. Credit requirements are governed under BPU approved BGS contracts.

Power

Counterparties expose Power s trading operation to credit losses in the event of non-performance or non-payment. Power has a credit management process, which is used to assess, monitor and mitigate counterparty exposure for Power and its subsidiaries. Power s counterparty credit limits are based on a scoring model that considers a variety of factors, including leverage, liquidity, profitability, credit ratings and risk management capabilities. Power s trading operations have entered into payment netting agreements or enabling agreements that allow for payment netting with the majority of its large counterparties, which reduce Power s exposure to counterparty risk by providing the offset of amounts payable to the counterparty against amounts receivable from the counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power s and its subsidiaries financial condition, results of operations or net cash flows. As of December 31, 2006, approximately 97% of the credit exposure (MTM plus net receivables and payables, less cash collateral) for Power s trading operations was with investment grade counterparties. The majority of the credit exposure with non-investment grade counterparties was with certain companies that supply fuel (primarily coal) to Power. Therefore, this exposure relates to the risk of a counterparty performing under its obligations rather than payment risk. As of December 31, 2006, Power s trading operations had over 121 active counterparties.

Energy Holdings

Global

Global has credit risk with respect to its counterparties to power purchase agreements (PPAs) and other parties.

Resources

As of December 31, 2006, Resources has a remaining gross investment in three leased aircraft of approximately $41 million, all with Northwest airlines. Resources successfully restructured the leases and converted them from leveraged leases to operating leases. Energy Holdings expects to recover its investment through cash flows from the operating leases.

Resources has credit risk related to its investments in leveraged leases, totaling $924 million, which is net of deferred taxes of $1.9 billion, as of December 31, 2006. These investments are largely concentrated in the energy industry. As of December 31, 2006, 67% of counterparties in the lease portfolio were rated investment grade by both S&P and Moody s. As of December 31, 2006, the weighted average credit rating of the lessees in Resources leasing portfolio was A /A3 by S&P and Moody s respectively.

Resources is the lessor of domestic generating facilities in several U.S. energy markets. Several of these lessees have credit ratings below investment grade. Resources investment in such transactions was approximately $264 million, net of deferred taxes of $510 million as of December 31, 2006. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Resources would record a pre-tax write-off up to its gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Resources portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to PSEG s and Energy Holdings financial position, results of operations and net cash flows.

Other Supplemental Information Regarding Market Risk

Power

The following table describes the drivers of Power s energy trading and marketing activities and Operating Revenues included in its Consolidated Statement of Operations for the year ended December 31, 2006. Normal operations and hedging activities represent the marketing of electricity available from Power s owned or contracted generation sold into the wholesale market. As the information in this table highlights, MTM activities represent a small portion of the total Operating Revenues for Power. Activities accounted for under the accrual method, including normal purchases and sales, account for the majority of the revenue. The MTM activities reported here are those relating to changes in fair value due to external movement in prices. For additional information, see Note 11. Financial Risk Management Activities of the Notes.

Operating Revenues
For the Year Ended December 31, 2006

	Normal Operations and Hedging(A)	Trading	Total
		(Millions)	
MTM Activities:			
Unrealized MTM Gains (Losses)			
Changes in Fair Value of Open Position	$ 13	$ 23	$ 36
Realization at Settlement of Contracts	(32)	(27)	(59)
Total Change in Unrealized Fair Value	(19)	(4)	(23)
Realized Net Settlement of Transactions Subject to MTM	32	27	59
Net MTM Gains	13	23	36
Accrual Activities:			
Accrual Activities Revenue, Including Hedge Reclassifications	6,021		6,021
Total Operating Revenues	$ 6,034	$ 23	$ 6,057

(A) Includes derivative contracts that Power enters into to hedge anticipated exposures related to its owned and contracted generation supply, all asset backed transactions (ABT) and hedging activities, but excludes owned and contracted generation assets.

The following table indicates Power s energy trading assets and liabilities, as well as Power s hedging activity related to ABTs and derivative instruments that qualify for hedge accounting under SFAS 133. This table presents amounts segregated by portfolio which are then netted for those counterparties with whom Power has the right to set off and therefore, are not necessarily indicative of amounts presented on the Consolidated Balance Sheets since balances with many counterparties are subject to offset and are shown net on the Consolidated Balance Sheets regardless of the portfolio in which they are included.

Energy Contract Net Assets/Liabilities
As of December 31, 2006

	Normal Operations and Hedging	Trading	Total
		(Millions)	
MTM Energy Assets			
Current Assets	$ 80	$ 44	$ 124
Noncurrent Assets	23	5	28
Total MTM Energy Assets	103	49	152
MTM Energy Liabilities			
Current Liabilities	$ (271)	$ (54)	$ (325)
Noncurrent Liabilities	(166)	(3)	(169)
Total MTM Energy Liabilities	(437)	(57)	(494)
Total MTM Energy Contract Net Liabilities	$ (334)	$ (8)	$ (342)

The following table presents the maturity of net fair value of MTM energy trading contracts.

Maturity of Net Fair Value of MTM Energy Trading Contracts
As of December 31, 2006

	Maturities within			
	2007	2008	2009-2011	Total
		(Millions)		
Trading	$ (10)	$ 2	$	$ (8)
Normal Operations and Hedging	(191)	(166)	23	(334)
Total Net Unrealized Losses on MTM Contracts	$ (201)	$ (164)	$ 23	$ (342)

Wherever possible, fair values for these contracts were obtained from quoted market sources. For contracts where no quoted market exists, modeling techniques were employed using assumptions reflective of current market rates, yield curves and forward prices as applicable to interpolate certain prices. The effect of using such modeling techniques is not material to Power s financial results.

PSEG, Power and Energy Holdings

The following table identifies losses on cash flow hedges that are currently in Accumulated Other Comprehensive Loss, a separate component of equity. Power uses forward sale and purchase contracts, swaps and firm transmission rights contracts to hedge forecasted energy sales from its generation stations and its contracted supply obligations. Power also enters into swaps, options and futures transactions to hedge the price of fuel to meet its fuel purchase requirements for generation. PSEG, Power and Energy Holdings are subject to the risk of fluctuating interest rates in the normal course of business. PSEG s policy is to manage interest rate risk through the use of fixed rate debt, floating rate debt and interest rate derivatives. The table also provides an estimate of the losses, net of taxes that are expected to be reclassified out of Accumulated Other Comprehensive Loss and into earnings over the next twelve months.

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss
As of December 31, 2006

	Accumulated Other Comprehensive Loss	Portion Expected to be Reclassified in next 12 months
	(Millions)	
Commodities	$ (108)	$ (27)
Interest Rates	(5)	(1)
Net Cash Flow Hedge Loss Included in Accumulated Other Comprehensive Loss	$ (113)	$ (28)

Power

Credit Risk

The following table provides information on Power s credit exposure, net of collateral, as of December 31, 2006. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value on open positions. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company s credit risk by credit rating of the counterparties.

Schedule of Credit Risk Exposure on Energy Contracts Net Assets
As of December 31, 2006

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
		(Millions)			(Millions)
Investment Grade External Rating	$ 619	$ 79	$ 619	1 (A)	$ 393
Non-Investment Grade External Rating	1		1		
Investment Grade No External Rating	23		23		
Non-Investment Grade No External Rating	22		22		
Total	$ 665	$ 79	$ 665	1	$ 393

(A) Counterparty is PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more collateral than the outstanding exposure, in which case there would not be exposure.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G), PSEG Power LLC (Power) and PSEG Energy Holdings L.L.C. (Energy Holdings). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G, Power and Energy Holdings each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and the consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

As discussed in Note 3 to the consolidated financial statements, on December 31, 2005, the Company adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Stockholder and Board of Directors of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY:

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, common stockholder s equity and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and the consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG POWER LLC:

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, capitalization and member s equity and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and the consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and the consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

As discussed in Note 3 to the consolidated financial statements, on December 31, 2005, the Company adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG ENERGY HOLDINGS L.L.C.:

We have audited the accompanying consolidated balance sheets of PSEG Energy Holdings L.L.C. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, member s equity and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and the consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2007

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions, except for share data)

	For The Years Ended December 31,		
	2006	2005	2004
OPERATING REVENUES	$ 12,164	$ 12,164	$ 10,610
OPERATING EXPENSES			
Energy Costs	6,769	7,040	5,824
Operation and Maintenance	2,297	2,282	2,147
Write-down of Assets	318		
Depreciation and Amortization	832	731	683
Taxes Other Than Income Taxes	133	141	139
Total Operating Expenses	10,349	10,194	8,793
Income from Equity Method Investments	120	124	119
OPERATING INCOME	1,935	2,094	1,936
Other Income	209	233	186
Other Deductions	(126)	(93)	(65)
Interest Expense	(808)	(784)	(774)
Preferred Stock Dividends	(4)	(4)	(4)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,206	1,446	1,279
Income Tax Expense	(454)	(560)	(484)
INCOME FROM CONTINUING OPERATIONS	752	886	795
Loss from Discontinued Operations, including Gain (Loss) on Disposal, net of tax benefit of $24, $154, and $44 for the years ended 2006, 2005 and 2004, respectively	(13)	(208)	(69)
INCOME BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	739	678	726
Cumulative Effect of a Change in Accounting Principle, net of tax benefit of $11 in 2005		(17)	
NET INCOME	$ 739	$ 661	$ 726

WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):						
BASIC		251,678		240,297		236,984
DILUTED		252,314		244,406		238,286
EARNINGS PER SHARE:						
BASIC						
INCOME FROM CONTINUING OPERATIONS	$	2.99	$	3.69	$	3.35
NET INCOME	$	2.94	$	2.75	$	3.06
DILUTED						
INCOME FROM CONTINUING OPERATIONS	$	2.98	$	3.63	$	3.34
NET INCOME	$	2.93	$	2.71	$	3.05
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$	2.28	$	2.24	$	2.20

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
(Millions)

	December 31,	
	2006	**2005**
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 141	$ 288
Accounts Receivable, net of allowances of $52 and $44 in 2006 and 2005, respectively	1,368	1,936
Unbilled Revenues	328	394
Fuel	847	812
Materials and Supplies	290	269
Prepayments	72	128
Restricted Funds	79	76
Derivative Contracts	127	377
Assets of Discontinued Operations	325	1,175
Assets Held for Sale	40	
Other	45	41
Total Current Assets	3,662	5,496
PROPERTY, PLANT AND EQUIPMENT	18,851	18,209
Less: Accumulated Depreciation and Amortization	(5,849)	(5,533)
Net Property, Plant and Equipment	13,002	12,676
NONCURRENT ASSETS		
Regulatory Assets	5,694	5,059
Long-Term Investments	3,868	4,077
Nuclear Decommissioning Trust (NDT) Funds	1,256	1,133
Other Special Funds	147	559
Goodwill	539	554
Intangibles	46	46
Derivative Contracts	55	42
Other	301	179
Total Noncurrent Assets	11,906	11,649

TOTAL ASSETS	$	28,570	$	29,821

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
(Millions)

	December 31, 2006	December 31, 2005
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 849	$ 1,536
Commercial Paper and Loans	381	100
Accounts Payable	964	1,154
Derivative Contracts	335	625
Accrued Interest	124	152
Accrued Taxes	152	141
Clean Energy Program	120	96
Liabilities of Discontinued Operations		436
Other	481	515
Total Current Liabilities	3,406	4,755
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	4,462	4,248
Regulatory Liabilities	646	726
Asset Retirement Obligations	509	585
Other Postretirement Benefit (OPEB) Costs	1,089	597
Accrued Pension Costs	327	67
Clean Energy Program	133	233
Environmental Costs	421	420
Derivative Contracts	204	656
Other	176	153
Total Noncurrent Liabilities	7,967	7,685
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,636	7,849
Securitization Debt	1,708	1,879
Project Level, Non-Recourse Debt	840	891
Debt Supporting Trust Preferred Securities	186	660

Total Long-Term Debt	10,370	11,279
SUBSIDIARIES PREFERRED SECURITIES		
Preferred Stock Without Mandatory Redemption, $100 par value, 7,500,000 authorized; issued and outstanding, 2006 and 2005 795,234 shares	80	80
COMMON STOCKHOLDERS EQUITY		
Common Stock, no par, authorized 500,000,000 shares; issued; 2006 266,372,440 shares; 2005 265,332,746 shares	4,661	4,618
Treasury Stock, at cost; 2006 13,727,032 shares; 2005 14,169,560 shares	(516)	(532)
Retained Earnings	2,710	2,545
Accumulated Other Comprehensive Loss	(108)	(609)
Total Common Stockholders Equity	6,747	6,022
Total Capitalization	17,197	17,381
TOTAL LIABILITIES AND CAPITALIZATION	$ 28,570	$ 29,821

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

	For The Years Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 739	$ 661	$ 726
Adjustments to Reconcile Net Income to Net Cash Flows from			
Operating Activities:			
(Gain) Loss on Disposal of Discontinued Operations, net of tax	(19)	178	(5)
Cumulative Effect of a Change in Accounting Principle, net of tax		17	
Gain (Loss) on Disposition of Property, Plant and Equipment	(5)	(8)	1
Write-Down of Property, Plant and Equipment	44		
Write-Down of Project Investments		22	
Depreciation and Amortization	850	767	721
Amortization of Nuclear Fuel	97	94	80
Provision for Deferred Income Taxes (Other than Leases) and ITC	(111)	224	167
Non-Cash Employee Benefit Plan Costs	237	235	217
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	64	(27)	(92)
Loss (Gain) on Sale of Investments	260	(122)	(79)
Undistributed Earnings from Affiliates	(44)	(46)	(12)
Foreign Currency Transaction Loss (Gain)	5		26
Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(30)	20	(4)
Over Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	111	109	80
Under Recovery of Societal Benefits Charge (SBC)	(140)	(120)	(158)
Net Realized Gains and Income from NDT Funds	(63)	(125)	(105)
Other Non-Cash Charges	62	61	57
Net Change in Certain Current Assets and Liabilities	173	(655)	25
Employee Benefit Plan Funding and Related Payments	(148)	(240)	(174)
Proceeds from the Withdrawal of Partnership Interests and Other Distributions	10	64	126
Other	(163)	(139)	8

Net Cash Provided By Operating Activities	1,929	970	1,605
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,015)	(1,053)	(1,247)
Investments in Joint Ventures, Partnerships and Capital Leases			(14)
Proceeds from Collection of Notes Receivable		120	
Proceeds from Sale of Discontinued Operations	494		43
Proceeds from Sale of Property, Plant and Equipment	5	229	13
Proceeds from the Sale of Investments and Return of Capital from Partnerships	246	315	399
Proceeds from NDT Funds Sales	1,405	3,223	2,637
Investment in NDT Funds	(1,427)	(3,232)	(2,647)
Restricted Funds	(5)	(54)	54
NDT Funds Interest and Dividends	40	35	28
Other	16	12	(22)
Net Cash Used In Investing Activities	(241)	(405)	(756)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	281	(538)	339
Issuance of Long-Term Debt	250	728	1,410
Issuance of Non-Recourse Debt		18	19
Issuance of Common Stock	83	533	83
Redemptions of Long-Term Debt	(1,594)	(271)	(2,232)
Repayment of Non-Recourse Debt	(51)	(37)	(70)
Redemption of Debt Underlying Trust Securities	(203)	(387)	
Cash Dividends Paid on Common Stock	(574)	(541)	(522)
Contributions from Minority Shareholders		(1)	
Other	(26		