PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 25, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

100 F ST., N.E.

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2009,

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
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza T25 Newark, New Jersey 07102-4194 973 430-7000	22-3663480

http://www.pseg.com

001-00973 **PUBLIC SERVICE ELECTRIC AND GAS COMPANY** **22-1212800**
(A New Jersey Corporation)
80 Park Plaza, P.O. Box 570
Newark, New Jersey 07101-0570
973 430-7000
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
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021	New York Stock Exchange
	6 3/4% Series VV, due 2016	
	8%, due 2037	
	5%, due 2037	

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

Registrant	Title of Each Class
PSEG Power LLC	Limited Liability Company Membership Interest
Public Service Electric and Gas Company	Medium-Term Notes, Series A, B, C, D, E, F and G

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 x	No ¨
PSEG Power LLC	Yes ¨	No x
Public Service Electric and Gas Company	Yes x	No ¨

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 x

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 x No ¨

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

Public Service Enterprise Group Incorporated	Yes x	No ¨
PSEG Power LLC	Yes ¨	No ¨
Public Service Electric and Gas Company	Yes ¨	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. x

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨
PSEG Power LLC	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨
Public Service Electric and Gas Company	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨

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 x

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2009 was $16,495,708,079 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 January 29, 2010 was 505,952,069.

As of January 29, 2010, 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 Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report 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 2010 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 8, 2010, 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, variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in energy industry law, policies and regulation, including market structures and rules and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit operations of our generating units,
- changes in nuclear regulation and/or developments in the nuclear power industry generally that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and trading risks,
- any deterioration in our credit quality,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- any inability to realize anticipated tax benefits or retain tax credits,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays or unforeseen cost escalations in our construction and development activities,

- increase in competition in energy markets in which we compete,

- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in discount rates and funding requirements, and

- changes in technology and increased customer conservation.

Additional information concerning these factors are set forth under Item 1A. Risk Factors.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we 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, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report only apply as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

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.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, Power, PSE&G and PSEG Energy Holdings L.L.C. (Energy Holdings). Depending on the context of each section, references to we, us, and our relate to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 201.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the U.S. Securities and Exchange Commission (SEC). You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., 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 our filed documents from commercial document retrieval services, the SEC s internet website at www.sec.gov or our website at www.pseg.com. Information contained on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through three direct wholly owned subsidiaries, Power, PSE&G and Energy Holdings, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSEG Services Corporation (Services), our wholly owned subsidiary, provides us and these operating subsidiaries with certain management, administrative and general services at cost.

As of and for the Year Ended December 31, 2009

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We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries operating results. Below are descriptions of our principal operating subsidiaries.

Power	PSE&G	Energy Holdings
A Delaware limited liability company formed in 1999 that integrates its generating asset operations with its wholesale energy sales, fuel supply, energy trading and marketing and risk management functions.	A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory.	A New Jersey limited liability company (successor to a company which was incorporated in 1989) that invests and operates through its two primary subsidiaries.
Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, capacity, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.	Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory.	Earns revenues from managing leveraged lease investments and the operation of its domestic generation projects.
		Also pursuing solar and other renewable generation projects.
	It is implementing several programs to improve efficiencies in customer energy use and increase the level of renewable generation.	

The majority of our earnings are derived from the operations of Power, which has contributed at least 70% of our Income from Continuing Operations over the past three years. While this part of the business has produced significant earnings over that period, its operations are subject to higher risks resulting from volatility in the energy markets. As a rate-regulated public utility, PSE&G has continued to be a stable earnings contributor for us. Earnings from Energy Holdings have significantly declined over the past few years as we sold virtually all of our investments in international projects. Energy Holdings earnings have also been impacted by gains and losses on its asset sales and other charges and impairments taken on its remaining investments.

Earnings (Losses) in millions	**2009**	**2008**	**2007**
Power	$ 1,189	$ 1,115	$ 1,000
PSE&G	325	364	380
Energy Holdings	72	(468)	12
Other	6	(28)	(67)
PSEG Income from Continuing Operations	**$ 1,592**	**$ 983**	**$ 1,325**

The following is a more detailed description of our business, including a discussion of our:

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BUSINESSOPERATIONS AND STRATEGY

Power

Through Power, we seek to produce low-cost energy by efficiently operating our nuclear, coal and gas-fired generation facilities, while balancing generation production, fuel requirements and supply obligations through energy portfolio management. We use commodity contracts and financial instruments, combined with our owned generation, to cover our commitments for Basic Generation Service (BGS) in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the spot market. These products and services include:

Energy the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kWh or dollars per MWh.

Capacity a product distinct from energy, is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch if it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period.

Ancillary Services related activities supplied by generation unit owners to the wholesale market, required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges imposed on market participants.

Emissions Allowances and Congestion Credits Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path.

Power also sells wholesale natural gas, primarily through a full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G s customers. The current BGSS contract runs through March 31, 2012.

About 44% of PSE&G s peak daily gas requirements comes from Power s firm transportation, which is available every day of the year. Power satisfies the remainder of PSE&G s requirements from field storage, liquefied natural gas, seasonal purchases, contract peaking supply, propane, refinery and landfill gas. Based upon availability, Power also sells gas to others.

How Power Operates

We own approximately 13,500 MWs of generation capacity located in the Northeast and Mid Atlantic regions of the U.S. in some of the country s largest and most developed electricity markets.

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The map below shows the locations of Power s Northeast and Mid Atlantic generation facilities.

We also own 2,000 MW of generation capacity in Texas which was transferred from Energy Holdings in October 2009. See Item 8. Financial Statements and Supplementary Data Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information.

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For additional information on each of our generation facilities, see Item 2. Properties.

Generation Capacity

Our installed capacity utilizes a diverse mix of fuels: 52% gas, 24% nuclear, 15% coal, 8% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2009 was approximately 59,800 GWh. The following table indicates the proportionate share of generating output by fuel type.

Generation by Fuel Type	Actual 2009
Nuclear:	
New Jersey facilities	35%
Pennsylvania facilities	16%
Fossil:	
Coal:	
New Jersey facilities	5%
Pennsylvania facilities	8%
Connecticut facilities	2%
Oil and Natural Gas:	
New Jersey facilities	15%
New York facilities	6%
Texas facilities	13%
Total	**100%**

The generation by our coal units in 2009 was adversely affected by the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units. This caused a decrease in our coal unit production in 2009 compared to 2008. We expect our coal unit generation to increase in 2010 as compared to 2009.

Generation Dispatch

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 31% base load, 50% load following and 19% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

¡ **Base Load Units** operate whenever they are available. These units generally derive revenues from energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower cost fuels. Performance is generally measured by the unit s capacity factor, or the ratio of the actual output to the theoretical maximum output. Our base load nuclear unit capacity factors were as follows:

Unit	Capacity Factor

Salem Unit 1	99.1%
Salem Unit 2	92.0%
Hope Creek	91.2%
Peach Bottom Unit 2	99.3%
Peach Bottom Unit 3	86.9%

No assurances can be given that these capacity factors will be achieved in the future.

- **Load Following Units** operate between 20% and 80% of the time. The operating costs are higher per unit of output due to lower efficiency and/or the use of higher cost fuels such as oil, natural gas and, in some cases, coal. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

- **Peaking Units** run the least amount of time and utilize higher-priced fuels. These units operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system load) is satisfied. Base load units are dispatched first, with load following units next, followed by peaking units. The following chart depicts the merit order of dispatch in PJM, where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that recent market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas generation to displace some coal generation:

The bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the locational marginal pricing (LMP) for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order

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without violating transmission reliability standards. Under such circumstances, the ISO will dispatch higher- cost generation out of merit order within the congested area and power suppliers will be paid an increased LMP in congested areas, reflecting the bid prices of those higher-cost generation units.

This method of determining supply and pricing creates an environment in the markets such that 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. Therefore, significant changes in the price of natural gas will often translate into significant changes in the wholesale price of electricity. This can be seen in the graphs below which present historical annual spot prices and forward calendar prices as averaged over each year.

Historical data and forward prices would imply that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which Power operates.

The prices reflected in the tables above do not necessarily illustrate our contract prices, but 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. In addition, the prices do not reflect locational differences resulting from congestion or other factors, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are highly volatile and there is no assurance that such prices will remain in effect nor that we will be able to contract output at these forward prices.

Fuel Supply

Nuclear Fuel Supply To run our nuclear units we have long-term contracts for nuclear fuel. These contracts provide for:

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

Coal Supply Coal is the primary fuel for our Hudson, Mercer, Keystone, Conemaugh and Bridgeport stations. We have contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge or ocean shipments.

In order to minimize emissions levels, our Bridgeport 3 and Hudson 2 units use a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources were not available for these facilities, their near-term operations would be adversely impacted. In the longer-term, additional material capital expenditures would be required to modify our Bridgeport 3 station to enable it to operate using a broader mix of coal sources. We anticipate completing the installation of pollution control equipment by the end of 2010 at our Hudson unit which will provide more flexibility in the types of coal we can use at that station.

Gas Supply Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with whom we have contracted. In addition, we have three firm gas transportation contracts to serve both of our Texas plants and have recently contracted for a firm transportation service for our Bethlehem Energy Center (BEC) in New York.

We have 1.2 billion cubic feet-per-day of firm transportation capacity under contract to meet the primary gas supply needs of our generation fleet and our obligations under the BGSS contract. We supplement that supply with a total storage capacity of 78 billion cubic feet.

Oil Oil is used as the primary fuel for two load following steam units and nine combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck, barge or pipeline.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Item 7. MD&A Overview of 2009 and Future Outlook and Note 12. Commitments and Contingent Liabilities.

Markets and Market Pricing

Power s assets are located in four centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC or, in the case of ERCOT, the Texas Public Utility Commission:

PJM Regional Transmission Organization PJM conducts the largest centrally dispatched energy market in North America. It serves over 51 million people, nearly 17% of the total U.S. population and a peak demand of over 144,000 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. All of Power s generating stations operate in PJM, except for the BEC, Guadalupe, Odessa, Bridgeport and New Haven stations**.**

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New York The NY ISO is the market coordinator for New York State and is now responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a peak demand of over 33,900 MW. Power s BEC station operates in New York.

New England ISO NE coordinates the movement of electricity in a region covering Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of over 28,000 MW. Power s Bridgeport and New Haven stations operate in Connecticut.

Texas The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to Texas customers representing 85 percent of the state s electric load and 75 percent of the Texas land area. The ERCOT service area has a population of about 22 million and a peak demand of over 63,400 MW. As the ISO for the region, ERCOT schedules power on the electric grid. Power s Guadalupe and Odessa plants operate in ERCOT.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials can serve to increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal and emissions, as well as the availability of our diverse fleet of generation units to produce these products, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility.

Since the majority of the power we generate has generally been sourced from lower-cost nuclear and coal units, the rise in electric prices in recent years has yielded higher margins for us. Over a longer-term horizon, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power, thereby placing us at risk should any of our generating units fail to function effectively or otherwise become unavailable.

In addition to energy sales, we also earn revenue from capacity payments for our assets in the Northeast and Mid-Atlantic U.S. These payments are compensation for committing that a portion of our capacity be available to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there is sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints, raising concerns about reliability and creating a more acute need for capacity. Previously, some generators, including us, announced the retirement or potential retirement of certain older generating facilities due to insufficient revenues to support their continued operation. To enable the continued availability of these facilities, in separate instances, both PJM and ISO-NE agreed to enter into Reliability-Must-Run (RMR) arrangements to compensate us for those units contribution to reliability.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater clarity regarding the value of capacity, resulting in an improved pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

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The prices to be received by generating units in PJM for capacity have been set through RPM base residual auctions and depend upon the zone in which the generating unit is located. The majority of our PJM generating units are located in zones where the following prices have been set.

Delivery Year	MW-day	kW-yr
June 2008 to May 2009	$ 148.80	$ 54.31
June 2009 to May 2010	$ 191.32	$ 69.83
June 2010 to May 2011	$ 174.29	$ 63.62
June 2011 to May 2012	$ 110.00	$ 40.16
June 2012 to May 2013	$ 139.73	$ 51.70

The zone in which our Keystone and Conemaugh units are located has experienced fewer constraints on its transmission system, and we have received prices lower than the prices for the rest of our PJM generating assets for periods through May of 2010. This is not the case for the periods from June 2010 to May 2012 when identical prices were set for all zones. However, the most recent auction, for the 2012-2013 delivery year, once again resulted in differing prices for various areas of PJM, with Keystone and Conemaugh receiving lower prices than the majority of our PJM generating units and our generating units in northern New Jersey receiving higher pricing.

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike these other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors will affect the capacity pricing, including but not limited to:

- changes in load and demand;
- changes in the available amounts of demand response resources;
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.);
- increases in transmission capability between zones; and
- changes to the pricing mechanism, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time.

For additional information on our collection of RMR payments in PJM and ISO-NE and the RPM and FCM proposals, see Regulatory Issues Federal Regulation.

Hedging Strategy

In an attempt to mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost nuclear and coal-fired generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-Fixed Price contract, a full requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the New Jersey Board of Public Utilities (BPU). The volume of BGS contracts and the electric utilities that our generation operations will serve vary from year to year.

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Pricing for the BGS contracts for recent and future periods by purchasing utility, including a capacity component, is as follows:

Load Zone ($/MWh)	2006-2009	2007-2010	2008-2011	2009-2012	2010-2013
PSE&G	$ 102.51	$ 98.88	$ 111.50	$ 103.72	$ 95.77
Jersey Central Power and Light	$ 100.44	$ 99.64	$ 114.09	$ 103.51	$ 95.17
Atlantic City Electric	$ 103.99	$ 99.59	$ 116.50	$ 105.36	$ 98.56
Rockland Electric Company	$ 111.14	$ 109.99	$ 120.49	$ 112.70	$ 103.32

A portion of our total capacity is hedged through the BGS auctions. On average, tranches won in the BGS auctions require 100 MW to 120 MW of capacity on a daily basis.

We have obtained price certainty for all of our PJM and New England capacity through May 2013 through the RPM and FCM pricing mechanisms.

We enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation. There is, however, variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units versus all units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey electric delivery company, that is, the load that remains after some customers have chosen to be served directly by third party suppliers. The amount of power supplied varies based on the level of the delivery company s default load, which is affected by the number of customers who choose a third party supplier, as well as by other factors such as weather and the economy. Historically, the number of customers that have switched to third party suppliers was relatively constant, but in 2009, as market prices declined from past years historic highs, there has been an incentive for more of the smaller commercial and industrial electric customers to switch. In a falling price environment, this has a negative impact on Power s margins, as the anticipated BGS pricing is replaced by lower market pricing. We are unable to determine the degree to which this switching, or migration , will continue, but the impact on our results could be material.

To support our contracted sales of energy, we entered into contracts for the future purchase and delivery of nuclear fuel and coal, which include some market-based pricing components. As of February 15, 2010, we had contracted for the following percentages of our nuclear and coal generation output and related fuel supplies for the next three years with modest amounts beyond 2012.

Nuclear and Coal Generation	2010	2011	2012
Generation Sales	90%-95%	50%-60%	15%-30%
Nuclear Fuel Purchases	100%	100%	100%
Coal Supply and Transportation Costs	95%-100%	30%-40%	5%-10%

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as these units are generally dispatched when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units have generally provided a lower contribution to our margin than either the nuclear or coal units, although recent market price dynamics of coal and gas moderated this historical relationship for 2009.

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case if little or no hedging activity had been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then current market.

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PSE&G

Our public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 5.5 million people, or about 70% of the State s population, reside.

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission** is the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the FERC.

- **Distribution** is the delivery of electricity and gas to the retail customer s home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the BPU.

We also earn margins through non-tariff competitive services, such as appliance repair services. The commodity supply portion of our utility business electric and gas sales are managed by BGS and BGSS suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

In addition to our current utility products and services, we have implemented several programs to improve efficiencies in customer energy use and increase the level of renewable generation including:

- a program to help finance the installation of 81 MW of solar power systems throughout our electric service area,

- a program to develop, own and operate 80 MW of solar power systems over four years, and

- a set of energy efficiency programs to encourage conservation and energy efficiency by providing energy and money saving measures directly to businesses and families.

For additional information concerning these programs and the components of our tariffs, see Regulatory Issues.

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How PSE&G Operates

We provide network transmission and point-to-point transmission services, which are coordinated with PJM, and provide distribution service to 2.1 million electric customers and 1.7 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our existing and future transmission investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Currently, approved rates provide for a ROE of 11.68% on existing and new transmission investment. FERC has also approved incentive rate treatment for two new transmission lines, which when added to the approved base ROE, will yield a ROE of 12.93% for these projects. We will also earn this ROE on Construction Work In Progress (CWIP) dollars spent on these projects.

Transmission Statistics

December 31, 2009		Historical Annual
Network Circuit Miles	**Billing Peak (MW)**	**Growth 2005-2009**
1,442	9,687	0.50%

For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation Transmission Regulation.

Distribution

Our primary business is the distribution of gas and electricity to end users in our service territory. Our load requirements were split during 2009 among residential, commercial and industrial customers, described below. We believe that we have all the non-exclusive franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

	% of 2009 Sales	
Customer Type	**Electric**	**Gas**
Commercial	58%	36%
Residential	31%	60%
Industrial	11%	4%
Total	**100%**	**100%**

While our customer base has remained steady, electric and gas load has declined, as illustrated:

Electric and Gas Distribution Statistics

	December 31, 2009		Historical Annual
	Number of Customers	**Electric Sales and Gas Sold and Transported**	**Load Growth 2005-2009**
Electric	2.1 Million	41,961 GWh	-0.6%
Gas	1.7 Million	3,500 Million Therms	-0.4%

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Supply

Although commodity revenues make up more than 60% of our revenues, we make no profit on the supply of energy since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. However, pursuant to BPU requirements, we serve as the supplier of last resort for electric and gas customers within our service territory who have not chosen another supplier. As a practical matter, this means we are obligated to provide supply to a vast majority of residential customers and a smaller portion of commercial and industrial customers.

We procure the supply to meet our BGS obligations through two concurrent auctions authorized by the BPU for New Jersey s total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey s electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set.

We procure the supply requirements of our default service gas customers (BGSS) through a full requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not have third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

There continues to be significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for both electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information see Item 7. MD&A.

Energy Holdings

With the transfer of the two Texas generation facilities to Power in October 2009 and the sale of almost all of our investments in international generation and distribution over the past few years, our focus at Energy Holdings is on managing our portfolio of leveraged lease investments and domestic generation investments. Through Energy Holdings, we are also pursuing solar and other renewable generation projects, as discussed below. For additional information on Energy Holdings generation facilities, see Item 2. Properties.

Products and Services

The majority of our $1.6 billion in leveraged lease investments are energy-related. As of December 31, 2009, the single largest lease investment represented 20% of total leveraged leases.

Our leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments 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, with respect to our lease investments, is not presented in our Consolidated Balance Sheets.

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. 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. Our ability to realize these tax benefits is dependent on operating gains

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generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

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 GAAP, the lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks related to certain lessees, see Item 1A. Risk Factors, Item 7. MD&A Results of Operations Energy Holdings, Item 7A. Quantitative and Qualitative Disclosures About Market Risk Credit Risk Energy Holdings and Note 12. Commitments and Contingent Liabilities.

Our domestic generation projects in California, Hawaii and New Hampshire, totaling 358 MW, are contracted under long-term Power Purchase Agreements (PPAs).

Energy Holdings has developed a 2 MW solar project in western New Jersey, currently in service, and acquired two additional solar projects of 27 MW, currently under construction in Florida and Ohio. Completion of the Florida and Ohio projects is expected by the end of 2010. The total investment for the three projects will be approximately $114 million.

In August 2008, we invested in a joint venture to license compressed air energy storage (CAES) technology. CAES technology stores energy in the form of compressed air which can later be released to generate electricity through specialized turbine equipment. This technology could be used to optimize an intermittent energy source, such as wind, by storing energy at night and releasing this stored energy during the day when customers need power. This technology can also be utilized to augment the capacity of Combined Cycle Gas Turbines, returning the units closer to their nameplate capacity when they are encountering reductions due to ambient conditions.

In October 2008, the New Jersey Office of Clean Energy (OCE) awarded a $4 million grant to a joint venture owned equally by us and an unaffiliated private developer, to advance the development of a 350 MW wind site to be located approximately 16 miles off the shore of southern New Jersey. An offshore wind site has not yet been developed and constructed in the U.S. Numerous issues, including federal and state permitting, environmental impacts, power output sale arrangements, construction approach and expected maintenance costs, will need to be resolved in order to successfully develop such a project.

COMPETITIVE ENVIRONMENT

Power

Various market participants compete with us and one another in buying and selling in wholesale power pools, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and

affiliates of other industrial companies.

New additions of lower cost or more efficient generation capacity could make our plants less economical in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in

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load requirements. A reduction in load requirements can also be caused by economic cycles and factors. It is also 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. To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing transmission planning or cost allocation could also impact our revenues.

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

Environmental issues, such as restrictions on carbon dioxide (CO_2) emissions and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. While our generation fleet is relatively low-emitting, additional restrictions could have a negative impact on certain of our units, including our coal units.

In addition, pressures from renewable resources, such as wind and solar, could increase over time, especially if government incentive programs continue to grow. For example, over the past several years, a sizable amount of wind generation capacity has been constructed in ERCOT, particularly in western Texas, which has impacted our Odessa generation facility located in that area. Given the favorable wind conditions in western Texas, these wind generation facilities are able to produce power during a substantial period of the year, resulting in an additional source of generation, especially during off-peak seasons. Numerous competitors have announced plans to build substantial amounts of new wind generation capacity in the western part of Texas, where power demand is relatively low, but there are transmission constraints in the ability to get power to the load centers. The Public Utility Commission of Texas is attempting to address the constraint issue, but it is not clear if these efforts at transmission expansion will be successful or, if so, what the economic impact will be. As a result of such potential transmission expansion, it is possible that additional amounts of wind generation may be built in ERCOT, potentially impacting market prices and our competitiveness.

PSE&G

The transmission and distribution business has minimal risks from competitors. Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

EMPLOYEE RELATIONS

As of December 31, 2009, we had approximately 10,352 employees in the following companies, including 6,627 covered under collective bargaining agreements.

Employees as of December 31, 2009

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,345	1,325	20	1,035
Union	1,561	5,057		9
Total Employees	**2,906**	**6,382**	**20**	**1,044**
Number of Union Groups	3	5	n/a	1

All of our collective bargaining agreements, except one will expire on April 30, 2013 or later. The one exception is an agreement at PSE&G that covers 1,218 employees. This agreement expires on April 30, 2011.

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REGULATORY ISSUES

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G, Power s generation and energy trading subsidiaries and one subsidiary of Energy Holdings are public utilities as defined by the FPA. FERC has extensive oversight over public utilities as defined by the FPA. FERC approval is usually required when a public utility company seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste, or geothermal resources. QFs must meet certain ownership, operating and efficiency criteria established by FERC. We own various QFs through Energy Holdings. QFs are subject to many, but not all, of the same FERC requirements as public utilities.

FERC also regulates ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales Generation/Market Issues
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Regulation of Wholesale Sales Generation/Market Issues

- ***Market Power*** Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to FERC for authority to make market based rate (MBR) sales. For a requesting company to receive MBR authority, FERC must first make a determination that the requesting company lacks market power in the relevant markets. FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power.

PSE&G and certain subsidiaries of Power and Energy Holdings have received MBR authority from FERC. Retention of MBR authority is critical to the maintenance of our generation business revenues.

Under MBR rules, FERC may look at sub-markets to analyze whether a company possesses market power. Applying these rules in October 2008, FERC granted PSE&G, PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC continued MBR authority and granted both PSEG Fossil LLC and PSEG Nuclear LLC initial MBR authority. Each of these companies will be required to file for continuation of its MBR authority by the end of 2010.

Cost-Based RMR Agreements FERC has permitted public utility generation owners to enter into RMR agreements that provide cost-based compensation to a generation owner when a unit proposed for retirement is asked to continue operating for reliability purposes. Our Hudson 1 generating station is currently operating under an RMR agreement which expires September 2011.

In ISO-NE, many owners of generation facilities have also filed for RMR treatment. We currently collect FERC-approved monthly payments for the Bridgeport Harbor Station Unit 2 and the New Haven Harbor Station. These agreements are scheduled to expire in June 2010.

RMR treatment has enabled these units to continue to operate. Various parties have challenged the continuation of RMR payments in ISO-NE and, thus, there is risk that such payments may be terminated prior to the end of the current contract terms.

Reactive Power Reactive power encompasses certain ancillary services necessary to maintain voltage support and operate the system. In 2008, we filed a reactive power Tariff with FERC, which was subsequently approved. Under this Tariff, we receive $28.5 million annually as compensation for the provision of reactive power.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units receive a single clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load). These FERC rules have a direct impact on the energy prices received by our units.

Capacity Markets

PJM, NYISO, and ISO-NE each have capacity markets that have been approved by FERC.

RPM is a locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. PJM s RPM and related FERC orders establishing prices paid to us and other generators as a result of RPM s transitional auctions are being challenged in court by various state public utility commissions, including the BPU. These legal actions remain pending. Moreover, the mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active.

Pursuant to a settlement that established the design of ISO-NE s market for installed capacity and which is being implemented gradually over a four-year period that commenced in December 2006, all generators in New England began receiving fixed capacity payments that escalate gradually over the transition period. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of generators on the system and contains incentive mechanisms to encourage generator availability during generation shortages. As in PJM, capacity market rules in the ISO-NE continue to develop. ISO-NE is expected to be filing soon with FERC to establish market rules for the fourth FCM auction to be held in August 2010.

NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. The NYISO capacity model recognizes only two separate zones that potentially may separate in price: New York City and Long Island. Discussions concerning potential changes to NYISO capacity markets are also ongoing.

Capacity market rules in all of these markets may change in the future.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are then trued up the following year to reflect actual annual expenses/capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments, and we have received incentive rates, affording a higher ROE, for large scale transmission investments. In October 2009, PSE&G filed its 2010 transmission rates with FERC and the rates became effective January 1, 2010. On February 2, 2010 FERC issued an order accepting our filing. The update provides for approximately $23 million in increased revenues as part of our 2010 transmission rates.

Transmission Expansion In June 2007, PJM identified the need for the construction of the Susquehanna-Roseland line, a new 500 kV transmission line intended to maintain the reliability of the electrical grid serving New Jersey customers. PJM assigned construction responsibility for the new line

to us and PPL for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is approximately $750 million, and PJM has directed that the line be placed into service by June 2012. On February 11, 2010, PSE&G received approval from the BPU to construct the New Jersey portion of the project. Additional approvals remain pending. For further discussion, see State Regulation Energy Policy Susquehanna-Roseland BPU Petition.

Construction of the Susquehanna-Roseland line is contingent upon obtaining all necessary federal, state, municipal and landowner permits and approvals. The construction of the line has encountered local opposition. Should the line be cancelled for reasons beyond our control, we will be entitled to recover 100% of prudently-incurred abandonment costs.

In December 2008, PJM approved another 500 kV transmission project, originating in Branchburg and ending in Hudson County, New Jersey. This project is still in the design phase and will require the receipt of numerous regulatory approvals prior to construction. In October 2009, we filed a petition with FERC seeking incentive rates for the planned project. In December 2009, FERC granted our request for incentive rate treatment. We will receive a ROE adder of 125 basis points above its base ROE, recovery of one hundred percent of Construction Work in Progress in rate base and authorization to recover 100% of all prudently-incurred development and construction costs if the project is abandoned or cancelled, in whole or in part, for reasons beyond our control. The estimated cost of the project is approximately $1.1 billion. PJM has specified a June 2013 in-service date for this project.

U.S. Department of Energy (DOE) Congestion Study, National Interest Electric Transmission Corridors and FERC Back-Stop Siting Authority By virtue of the Energy Policy Act, the DOE has the ability to designate transmission corridors in areas found to be critical congestion areas, which then gives FERC the ability to site transmission projects within these corridors should certain events occur.

In October 2007, the DOE acted to designate transmission corridors within these critical congestion areas. One of the designated corridors is the Mid-Atlantic Area National Corridor which includes New Jersey, most of Pennsylvania and New York. Thus, entities seeking to build transmission within the Mid-Atlantic Area Corridor may be able to use FERC s back-stop siting authority under certain circumstances, if necessary, to site transmission, including the Susquehanna-Roseland line. In February 2009, the United States Court of Appeals for the Fourth Circuit issued a decision that would narrow the scope of FERC s back-stop siting authority. The United States Supreme Court has declined to review this decision. The DOE is required by statute to issue a new congestion study in 2010.

PJM Transmission Rate Design In 2007, FERC addressed the issue of how transmission rates, paid by PJM transmission customers and ultimately paid by our retail customers, should be designed in PJM. FERC ruled that the cost of new high voltage (500 kV and above) transmission facilities in PJM would be regionalized and paid for by all transmission customers on a pro-rata basis, which share is calculated annually based upon a zone s load ratio share within PJM. For all existing facilities, costs would be allocated using the pre-existing zonal rate design. For new lower voltage transmission facilities, costs would be allocated using a beneficiary pays approach. This FERC decision was subsequently upheld on rehearing but was then appealed by other parties to the United States Court of Appeals for the Seventh Circuit.

In August 2009, the Court ruled that with respect to new 500 kV and higher centrally-planned facilities, FERC had not adequately justified its decision to regionalize these costs. Certain parties sought rehearing of the Court s decision, which requests have been denied. The case has now been remanded to FERC for further proceedings. FERC has established procedures for review of this issue. The current allocation for new 500 kV and higher centrally-planned projects may remain in place or could be modified by FERC.

Compliance

Reliability Standards Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability

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of the U.S. electric transmission and generation system and to prevent major system blackouts. Many reliability standards have been developed and approved. These standards apply both to reliability of physical assets interconnected to the bulk power system and to the protection of critical cyber assets. Since these standards are mandatory and applicable to, among other entities, transmission owners and generation owners and operators, we are obligated to comply with the standards and to ensure continuing compliance. Our Texas and California generation assets, as well as PSE&G, have already undergone formal audits, and our generation assets in PJM will be audited in 2011. In addition, many of our operating companies have been subject to spot audits. NERC compliance represents a significant area of compliance responsibility for us. As a result of a PSE&G audit, NERC has assessed a penalty of five thousand dollars with respect to a potential violation of one NERC standard. This penalty is now pending at FERC.

FERC Standards of Conduct In October 2008, FERC issued a revised rule governing the interaction between transmission provider (i.e. PSE&G) employees and wholesale merchant employees (housed largely in Power), which revises FERC s Standards of Conduct by abandoning the corporate separation approach to regulating these interactions and instead adopting an employee function approach, which focuses on an individual employee s job functions in determining how the rules will apply. The effect of these rules will be to permit more affiliate communication with respect to corporate and strategic planning, to loosen restrictions on senior officers and directors and to permit necessary operational communications between those employees engaged in transmission system operations and planning and those employees engaged in generating plant operations. In October 2009, FERC revised these rules to further define which employees are covered by the rules. Because of the rules focus on employee functions, all of our FERC regulated companies will need to continue to monitor developments in this area.

Market Behavior/Anti-Manipulation Rules FERC has rules in place to govern the behavior of participants in the wholesale energy markets that it regulates. These rules prohibit such participants from engaging in certain types of transactions, such as withholding generating capacity to artificially increase prices, engaging in wash trades and providing erroneous or misleading information to, or withholding material information from, Regional Transmission Organizations (RTO)/ISOs. FERC s anti-manipulation rules are broadly written and are intended to prevent market participants from engaging in fraudulent conduct in FERC regulated markets. These rules are now very much a focus of FERC s compliance efforts, and during the last year, FERC has imposed significant monetary penalties on market participants found to be in violation of the rules. All of our companies that do business in FERC regulated markets, such as PSE&G and subsidiaries of Power, must comply with these rules.

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Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive 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. In August 2009, we submitted applications to extend the operating licenses of our Salem and Hope Creek facilities by 20 years. No parties have requested a hearing or intervention and the initial filing deadline for such a request as part of the NRC license renewal process has passed. The NRC is expected to spend up to 30 months to review our applications before making a decision. The current operating licenses of our nuclear facilities expire in the years shown below:

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

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. Our utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We are also subject to some state regulation in California, Connecticut, Hawaii, New Hampshire, New York, Pennsylvania and Texas due to our ownership of generation and/or transmission facilities in those states.

Rates

Electric and Gas Base Rates We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. The BPU also has authority to adjust rates downward if it finds that the rates it approved are no longer just and reasonable. In May 2009, we petitioned the BPU for an increase in electric and gas base rates. We filed an update in January 2010 requesting an increase of $148 million and $74 million for electric and gas, respectively. The matter is pending with a decision expected in the first half of 2010. No assurances can be given regarding the outcome of this proceeding.

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Rate Adjustment Clauses In addition to base rates, we recover certain costs from customers pursuant to mechanisms, known as adjustment clauses. These clauses permit, at set intervals, the flow-through of costs to customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs are subject to BPU approval. Costs associated with these clauses are deferred when incurred and amortized to expense when recovered in revenues. Delays in the pass-through of costs under these clauses can result in significant changes in cash flow. Our Societal Benefits Charges (SBC) and Non-utility Generation Charges (NGC) clauses are detailed in the following table:

Rate Clause	2009 Revenue	(Over) Under Recovered Balance as of December 31, 2009
	Millions	
Energy Efficiency and Renewable Energy	$ 197	$ (4)
Remediation Adjustment Charges (RAC)	18	137
USF	179	8
Social Programs	54	47
Total SBC	**448**	**188**
NGC	102	86
Total	**$ 550**	**$ 274**

SBC The SBC is a mechanism designed to ensure recovery of costs associated with activities required to be accomplished to achieve specific government-mandated public policy determinations. The programs that are covered by the SBC (gas and electric) are energy efficiency and renewable energy programs, Manufactured Gas Plant Remediation Adjustment Charge (RAC) and the Universal Service Fund (USF). In addition, the electric SBC includes a Social Programs component. All components include interest on both over and under recoveries.

NGC The NGC recovers the above market costs associated with the long-term power purchase contracts with non-utility generators approved by the BPU.

Recent Rate Adjustments

USF/Lifeline The USF is an energy assistance program mandated by the BPU under state law to provide payment assistance to low-income customers. The Lifeline program is a separately mandated energy assistance program to provide payment assistance to elderly and disabled customers. In October 2009, revised rates were put in place. Our USF rates will recover $75 million and $38 million for electric and gas, respectively. Our Lifeline rates will recover $29 million and $16 million for electric and gas, respectively. We earn no margin on the collection of the USF or Lifeline programs, resulting in no impact on Net Income.

SBC/NGC In February 2009, we filed a petition requesting a decrease in our electric SBC/NGC rates of $18.9 million and an increase in gas SBC rates of $3.7 million. In July 2009, a revision was filed requesting an increase in SBC/NGC rates of $104 million and $15 million for electric and gas, respectively. The electric increase was due to increased non-utility generation (NUG) contract costs. We expect an initial decision from the Administrative Law Judge in March and a BPU order in April 2010. No assurances can be provided as to the outcome of these proceedings.

RAC In November 2009, we filed a RAC 17 petition with the BPU requesting an increase in electric and gas RAC rates of approximately $13.4 million and $10.5 million, respectively. This matter was transferred to the Office of Administrative Law.

Energy Supply

BGS New Jersey s EDCs provide two types of BGS, the default electric supply service for customers who do not have a third party supplier. The first type, which represents about 80% of PSE&G s load

requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Fixed Price). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

All of New Jersey s EDCs jointly procure the supply to meet their BGS obligations through two concurrent auctions authorized each year by the BPU for New Jersey s total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers provide BGS to New Jersey s EDCs. PSE&G earns no margin on the provision of BGS.

PSE&G s total BGS-Fixed Price eligible load is expected to be approximately 8,500 MW. Approximately one-third of this load is auctioned each year for a three-year term. Current pricing is as follows:

	2007	2008	2009	2010
36 Month Term Ending	May 2010	May 2011	May 2012	May 2013
Load (MW)	2,758	2,800	2,900	2,800
$ per kWh	$ 0.09888	$ 0.11150	$ 0.10372	$ 0.09577

(a) Prices set in the February 2010 BGS Auction are effective on June 1, 2010 when the 36-month (May 2010) supply agreements expire.

In December 2009, the BPU decided that, after the 2010 BGS auction, it would hold a technical conference to consider enhancements to the BGS auction. Any action taken in response to that hearing is likely to be implemented for the BGS auctions in 2011 or future years. The BPU may address many issues, including the impact of potential development of incremental generation in New Jersey. No assurances can be provided as to the outcome of these proceedings.

For additional information, see Item 8. Financial Statements and Supplementary Data Note 6. Regulatory Assets and Liabilities and Note 12. Commitments and Contingent Liabilities.

BGSS BGSS is the mechanism approved by the BPU designed to recover all gas costs related to the supply for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G s revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time.

PSE&G has a full requirements contract through March 2012 with Power to meet the supply requirements of default service gas customers. Power charges PSE&G for gas commodity costs which PSE&G recovers from customers. Any difference between rates charged by Power under the BGSS contract and rates charged to PSE&G s residential customers are deferred and collected or refunded through adjustments in future rates. PSE&G earns no margin on the provision of BGSS.

In May 2009, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $133 million, excluding Sales and Use Tax, to be effective October 1, 2009. This represents a reduction of approximately 7% for a typical residential gas heating customer. The BPU approved the new lower BGSS rate on September 16, 2009 and it became effective immediately.

Energy Policy

New Jersey Energy Master Plan (EMP) New Jersey law requires that an EMP 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. The most recent EMP was finalized in October 2008. The plan identifies a number of the actions to improve energy efficiency, increase the use of renewable resources, ensure a reliable supply of energy and stimulate investment in clean energy technologies. Given the gubernatorial change in New Jersey, it is unclear what changes to the EMP and its policy goals may result. We have approval from the BPU to implement several programs addressing different components of the EMP goals to improve efficiencies in customer use and increase the level of renewable generation in New Jersey.

Solar Initiatives In order to spur investment in solar power in New Jersey and meet energy goals under the EMP we have undertaken two major initiatives at PSE&G. The first program helps finance the installation of 81 MW of solar systems throughout our electric service area by providing loans to customers. The first part of this initiative was a pilot program approved by the BPU in April 2008. The program was expanded beyond its pilot phase in December 2009. The program is similar to the original pilot program, but it is available only for systems up to 500kW. The borrowers can repay the loans over a period of either 10 years (for residential customer loans) or 15 years (for non-residential customers), by providing us with solar renewable energy certificates (SRECs) or cash. The value of the SRECs towards the repayment of the loan is guaranteed to be not less than a floor price. SRECs received by us in repayment of the loan are sold through a periodic auction. Proceeds will be used to offset program costs.

The total investment of both phases of the Solar Loan Program will be approximately $248 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2009, we have provided $43 million in loans for 53 projects representing 11.6 MW.

The second solar initiative is the Solar 4 All Program that was approved by the BPU in July 2009. Under this program, we are investing approximately $515 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of systems 500kW or greater installed on PSE&G-owned property (25 MW), solar panels installed on distribution system poles (40 MW) and PV systems installed on third-party sites in our electric service territory (15 MW). We will sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition we will sell the SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales will be used to offset program costs.

As of December 31, 2009, 1 MW of solar panels had been installed on distribution poles. On January 6, 2010, we announced that we had entered into contracts with four developers for 12 MW of solar capacity to be developed on land we own in Edison, Linden, Trenton and Hamilton. The projects represent an investment of approximately $50 million. Construction is expected to start this spring pending receipt of all approvals.

Demand Response (DR) In 2008 the BPU directed that DR programs be implemented by each of New Jersey s electric utilities and established targets to increase DR by a total of 600 MW by the end of the third year, with our responsibility being 55% of the total (330 MW). We filed our program proposal and identified $93.4 million of demand response investment over a period of four years, seeking full recovery of the program costs, including a return on our investment, through rates.

In July 2009, the BPU approved a portion of our program that focuses on air conditioning load control in the residential and small commercial customer segments. The investment represents $65.3 million with a target of 150 MW to be achieved. The remaining portion of our filing is awaiting further action by the BPU, but no timetable has been established to complete the proceeding. As of December 31, 2009, we had installed approximately 1.2 MW.

Also in 2008, the BPU directed each of the State s electric utilities to administer a one-year program designed to develop an additional 600 MW of DR resources. The utilities role was to collect funding through rates and make payments to Curtailable Service Providers who signed up the new or incremental DR resources. The incentive was set by the BPU at $22.50/MW-day with a statewide budget of $4.9 million. Our share was set at 59.54%, or 195 MW, with a budget of $3.4 million. Funding for the program, called the Demand Response Working Group Modified Program, was

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collected through a component of the Regional Greenhouse Gas Initiative (RGGI) Adjustment Clause in 2009. We anticipate paying approximately $1.1 million in February 2010 for the 132 MW verified by PJM.

Energy Efficiency Initiatives We have been approved by the BPU to implement two energy efficiency initiatives, both of which were filed under New Jersey s RGGI legislation, which encourages utilities to invest in conservation and energy efficiency programs as part of their regulated business. Both initiatives are intended to help New Jersey meet its EMP goal of reducing energy consumption by 20% by 2020 and to help improve New Jersey s economy through the creation of new jobs through the promotion of energy efficiency.

- ***Carbon Abatement Program*** The BPU approved our proposal to invest up to $46 million over four years on a small scale carbon abatement program across specific customer segments. New rates were effective on January 1, 2009. For each year of the program we will file a petition on October 1st to set forth the calculation of the electric and gas recovery charges for the subsequent year. The BPU approved a rate increase in December 2009, which will result in a net annual revenue increase of $1.9 million in 2010.

- ***Energy Efficiency Economic Stimulus Program*** In July 2009, the BPU approved our energy efficiency program developed to stimulate economic growth in the state. Under this program, we anticipate approximately $190 million in energy efficiency expenditures over an 18 month period. The program provides for a charge for recovery of program expenditures plus an allowed return.

The energy efficiency initiatives target multiple customer segments. Subprograms provide energy audits and incentives for energy retrofit services to homes and small businesses in Urban Enterprise Zone municipalities, multi-family buildings, hospitals, data centers and governmental entities. Other initiative components include funding for new technologies and demonstration projects, and a program to encourage non-residential customers to reduce energy use through improvements in the operation and maintenance of their facilities.

Capital Economic Stimulus Infrastructure Program In January 2009, we filed for approval of a capital economic stimulus infrastructure investment program. Under this initiative, we proposed to undertake $698 million of capital infrastructure investments over a 24 month period. The goal of these accelerated capital investments is to help improve the State s economy through the creation of new jobs. This filing was made in response to the Governor of New Jersey s proposal to help revive the economy through job growth and capital spending.

In April 2009, the BPU approved a settlement agreement which identified 38 qualifying projects totaling $694 million. These projects are expected to create more than 900 new jobs. We received the BPU s written order effective May 1, 2009, which provides increases of $7 million for electric and $12 million for gas rates annually. Under the program, new Capital Adjustment Charges (CAC) will provide for immediate recovery of a return on program expenditures plus depreciation of the assets. The CAC will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting. The rates are subject to annual adjustments based on actual expenditures and market conditions.

In November 2009, PSE&G made a filing in the above-referenced matter, requesting approximately $35 million for electric and $17 million for gas in revenue, on an annual basis for a combined total of $52 million. Compared to the existing BPU approved CAC rates, the resultant total net annual revenue impact on the electric and gas customers is a $33 million increase over the 2009 rates. In December 2009, the BPU approved a stipulation to reset the CAC effective January 1, 2010.

Susquehanna-Roseland BPU Petition In January 2009, we filed a Petition with the BPU seeking authorization to construct the New Jersey portion of the Susquehanna-Roseland line. The New Jersey portion of the line spans approximately 45 miles and crosses through 16 municipalities. The Petition seeks a finding from the BPU that municipal land use and zoning ordinances do not apply to this line.

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On February 11, 2010, the BPU granted approval to PSE&G to construct the New Jersey portion of this project. In June 2009, the New Jersey Highlands Council provided a favorable applicability determination with respect to the portion of the project crossing the Highlands region, and the New Jersey Department of Environmental Protection (NJDEP) approved this determination on January 15, 2010. We are in the process of seeking to obtain all other necessary environmental permits for the project, including from the National Park Service, as may be necessary. Failure to obtain all permits on a timely basis could delay the project.

BPU Audits

The BPU has statutory authority to conduct periodic audits of our utility s operations and our compliance with applicable affiliate rules and competition standards. The BPU has begun conducting its periodic combined management/competitive service audits of PSE&G.

Management/Affiliate Audit The BPU engaged a contractor to perform a comprehensive audit with respect to the effectiveness of management and transactions among affiliates, which began in October 2009. According to the BPU schedule the audit will be completed as early as July 2010. A report will be produced which can be expected to include recommendations for changes in practices at PSE&G and affiliates. We will have an opportunity to provide comments. The BPU may enforce the findings in whole or in part by Order.

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. For additional information regarding the Deferral Audit, see Item 1A. Risk Factors and Note 12. Commitments and Contingent Liabilities.

RAC Audit In February 2008, the BPU s Division of Audits commenced a review of the RAC program for the RAC 12, 13 and 14 periods encompassing August 1, 2003 through July 31, 2006. Total RAC costs associated with this period were $83 million. The BPU has not issued a final order or report. We cannot predict the final outcome of this audit.

ENVIRONMENTAL MATTERS

Environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to address the environmental impacts of historical operations that may have been in full compliance with the requirements in effect at the time those operations were conducted. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with current pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known and are not included in capital expenditures, but may be material.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- water pollution control,
- hazardous substance liability,
- fuel and waste disposal, and

climate change.

For additional information related to environmental matters, including anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Note 12. Commitments and Contingent Liabilities.

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Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws.

Title V of the CAA requires all major sources such as our generation facilities to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in capital expenditures, but may be material.

Sulfur dioxide (SO_2), Nitrogen Oxide (NO_x) and Particulate Matter Emissions Since January 1, 2000, the CAA set a cap on SO_2 emissions from affected generating units and allocated SO_2 allowances to those units with the stated intent of reducing the impact of acid rain. Generation units with emissions greater than their allocations can obtain allowances from sources that have excess allowances. We do not expect to incur material expenditures to continue complying with this SO2 program, known as the acid rain program.

The U.S. Environmental Protection Agency (EPA) further regulated SO_2 and NOx by enacting the final Clean Air Interstate Rule (CAIR). In this rule, the EPA identified 28 states and the District of Columbia as contributing significantly to the levels of fine particulates and/or eight-hour ozone air quality in states downwind of those states identified by EPA. New Jersey, New York, Pennsylvania, Texas and Connecticut were among the states the EPA listed as contributing to downwind particulate and eight-hour ozone air quality. Based on state obligations to address interstate transport of air pollutants under the CAA, the EPA had proposed a two-phased emission reduction of both NO_x and SO_2, which are precursors to both particulate matter emissions and ozone air quality. Under CAIR, both NO_x and SO_2 are regulated under two phases, which correspond to the emissions levels expected to be obtained by certain dates during those phases. Phase 1of CAIR was scheduled to begin in 2009 for emissions of NO_x and 2010 for emissions of SO_2. Phase 2 of CAIR for NOx and SO_2 emissions were scheduled to begin 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.

CAIR was challenged by a variety of states, environmental groups and industry groups. In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR back to the EPA to fix what the Court identified as the flaws within CAIR. The existing CAIR will remain in effect until the EPA issues new rules.

Based upon the remand order, the NO_x trading program commenced in 2009. It is anticipated that, in aggregate, we will be net buyers of annual NO_x allowances but will likely be allocated sufficient allowances to satisfy Ozone season NO_x emissions. At recent market prices of annual NO_x allowances, the cost of our estimated shortfall requirement of 3,000 allowances would be approximately $10 million. The future direction of the market is unclear due to the recent court rulings. The final cost of compliance is uncertain due to market instability.

The SO_2 part of CAIR was initiated on January 1, 2010, and the financial impact to us is anticipated to be minimal due to the surplus allowances banked from the acid rain program that can be used to satisfy CAIR obligations. CAIR redesign is expected to be proposed in the second quarter of 2010. The impacts of this redesign cannot be determined at this time.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters 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 those in New Jersey, New York, Connecticut and Texas, to administer the NPDES program through state acts. We also have ownership interests in 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 our facilities in those jurisdictions.

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In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling, in other words, the use of cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

Hazardous Substance Liability

The production and delivery of electricity, distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources.

Site Remediation The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.

Natural Resource Damages CERCLA and the Spill Act authorize the assessment of 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. 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. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change.

Fuel and Waste Disposal

Nuclear Fuel Disposal 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. In September 2009, we signed an agreement with the DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE delay in accepting spent nuclear fuel for permanent disposition. Under this settlement, in October 2009 we received approximately $47 million for our spent fuel management costs incurred through December 2007 and in January 2010 we received approximately $7 million for those costs incurred during 2008. A similar settlement agreement was reached related to Peach Bottom in 2004.

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 the reactor. We have an on-site storage facility that is expected to satisfy the storage needs of Salem 1, Salem 2 and Hope Creek through the end of their current licenses as well as storage needs over the units anticipated 20 year license extensions. Exelon Generation has advised us that it has an on-site storage facility that will satisfy Peach Bottom s storage requirements until at least 2014.

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Low Level Radioactive Waste As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste 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 continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. There are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.

Climate Change

In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Ten Northeastern states, including New Jersey, New York and Connecticut, have established RGGI intended to cap and reduce CO_2 emissions in the region. In general, these states adopted state-specific rules to enable the RGGI regulatory mandate in each state.

States rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, 2011). Allowances are available through the auction or through secondary markets and are required to be submitted to states by March 2012 for the first period.

Pricing for the allowances will vary based on future allowance market conditions, electric generation market conditions and the possibility of a national greenhouse gas program that may or may not supplant RGGI.

New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its greenhouse gas emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Concurrently, the federal government is considering several bills to define a national energy policy and address climate change. Bills under consideration include provisions to establish a national renewable energy portfolio standard, to establish an energy efficiency resource standard and to implement a cap-and-trade program to reduce greenhouse gas emissions. Provisions contained within these bills may present material risks and opportunities to our businesses. Ultimately, the final design of the federal climate change bill specifically with regard to the stringency and integrity of the carbon cap, the design of price control mechanisms, rules governing the use of offsets, how emissions allowances are allocated and provisions for preemption of State, regional, and EPA programs will determine the impact of the legislation on us. We will not be able to reasonably estimate these impacts until final legislation is passed.

The EPA has issued an endangerment finding for greenhouse gas emissions, and is in the process of defining how it will apply Preventions of Significant Deterioration (PSD)/ Best Available Control Technology (BACT) requirements for greenhouse gas emissions at new and or modified sources. The scope and stringency of these requirements will determine their impact to the electric power industry and us.

For additional information on various activities at the federal level during 2009 related to addressing global climate change, see Item 7. MD&A Overview of 2009 and Future Outlook.

The outcome of global climate change initiatives cannot be determined; however, adoption of stringent CO_2 emissions reduction requirements in the Northeast, including the potential allocation of allowances to our facilities and the prices of allowances available through auction, could materially impact our operations. The financial impact of a requirement to purchase allowances for emissions of CO_2 would be greatest on coal-fired generating units because they typically have the highest CO_2 emission rate and therefore, need to purchase the most allowances. Gas-fired units would require fewer allowances and nuclear units would not need any allowances.

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Any addition of CO_2 limit requirements under a national program could impose an additional financial impact on our fossil generation activities beyond that imposed by existing state and regional programs. It is premature to determine the positive or negative financial impact of a future federal climate change program because it is difficult to determine the effect of such program on the dispatch of our electric generation units compared to the dispatch of other power generating companies, particularly those which may have a larger carbon footprint.

While there would be increased costs relating to these evolving regulations, the efforts to reduce greenhouse gases could lead to increased opportunities associated with renewable generation and other alternative fuels. Moreover, to the extent that a carbon charge applies to gas and coal generation, we could experience higher margin from the sale of energy produced by our nuclear facilities. However, it is premature to attempt to quantify the possible costs and other implications of our generation facilities.

In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings not involving our companies could be material in the future liability of energy companies on alleged impacts of global climate change. Litigation has been commenced by individuals, local governments and interest groups alleging that various industries, including various energy companies, emitted greenhouse gases causing global climate change that resulted in a variety of damages. If relevant Federal or state common law were to develop that imposed liability upon those that emit greenhouse gases for alleged impacts of greenhouse gas emissions, such potential liability could be material.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Note 21. Financial Information by Business Segment.

ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this document.

The factors discussed in Item 7. MD&A may also have a material adverse affect our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our business.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our business, such as our ability to:

- ***Obtain fair and timely rate relief*** Our utility s base rates for electric and gas distribution are subject to regulation by the BPU and are effective until a new base rate case is filed and concluded. In addition, limited categories of costs such as fuel are recovered through adjustment clauses that are periodically reset to reflect current costs. Our transmission assets are regulated by FERC and costs are recovered through rates set by FERC. Inability to obtain a fair return on our investments or to timely recover material costs not included in rates would have a material adverse effect on our business.

- ***Obtain required regulatory approvals*** The majority of our businesses operate under MBR authority granted by FERC, which has determined that our subsidiaries do not have market power and MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter

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into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals could materially adversely affect our results of operations and cash flows.

Obtain adequate levels of energy and capacity payments The rules governing the energy and capacity markets in which we participate are approved by FERC and are subject to change. These rules have been challenged and will continue to be challenged in the future. Changes may have an adverse impact on the amount of payments we receive in these markets

Comply with regulatory requirements There are Federal standards in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. These standards apply to all transmission owners and generation owners and operators. We have been, and will continue to be, periodically audited by NERC for compliance. In addition, as of December 31, 2009, our companies with critical cyber assets must be in compliance with NERC s Critical Infrastructure Protection (CIP) Standards. FERC can impose penalties up to $1 million per day per violation. In addition, FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, interlocking directorate rules and cross-subsidization.

The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. We are currently in the process of undergoing a management audit and an affiliate transactions audit. While we believe that we are in compliance, we cannot predict the outcome of such audits.

There are two pending issues at the BPU stemming from the restructuring of the utility industry in New Jersey several years ago.

Treatment of previously approved stranded costs Our utility securitized $2.525 billion of generation and generation-related costs pursuant to an irrevocable, non-bypassable BPU financing order issued pursuant to the Competition Act. The authority of the BPU to issue its order was upheld by the New Jersey Supreme Court in 2001. The Competition Act created a property right in such financing order that was sold to a bankruptcy remote special purpose subsidiary of PSE&G. An action filed in 2007, seeking injunctive relief from our continued collection of the related transition bond charges, as well as recovery of amounts previously charged and collected, was summarily dismissed by the New Jersey Superior Court and affirmed on appeal in February 2009. The New Jersey Supreme Court denied the plaintiff s petition for certification in May 2009. In addition, a related petition was filed at the BPU, and our Motion to Dismiss the petition remains pending. For additional information, see Legal Proceedings. We cannot predict the outcome of the action pending at the BPU.

Market Transition Charge (MTC) collected during the four-year industry transition period The BPU has raised certain questions with respect to the reconciliation method we employed in calculating the over-recovery of MTC and other charges during the four-year transition period from 1999 to 2003. The amount in dispute was $114 million, which if required to be refunded to customers with interest through December 2009 would be $142 million. In January 2009, an Administrative Law Judge (ALJ) issued a decision which upheld our central contention that the 2004 BPU order approving the Phase I settlement resolved the issues now raised by the BPU Staff and the New Jersey Division of Rate Counsel, and that these issues should not be subject to re-litigation in respect of the first three years of the transition period. The ALJ s decision states that the BPU could elect to convene a separate proceeding to address the fourth and final year reconciliation of MTC recoveries. The amount in dispute with respect to this Phase II period is approximately $50 million.

By order dated September 3, 2009, the BPU rejected the ALJ s initial decision, elected to maintain jurisdiction over the matter and established a schedule for briefing on the merits of the question of whether any MTC-related refunds are due. Generally, the BPU rejected the claims that the matters at issue had been fairly and finally litigated. Briefing has been completed and the matter is now pending before the BPU. We cannot predict the outcome of this proceeding.

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Certain of our leveraged lease transactions may be successfully challenged by the IRS, which would have a material adverse effect on our taxes, operating results and cash flows.

We have received Revenue Agent s Reports from the IRS with respect to its audit of our federal corporate income tax returns for tax years 1997 through 2003, which disallowed all deductions associated with certain leveraged lease transactions. In addition, the IRS Reports proposed a 20% penalty for substantial understatement of tax liability.

As of December 31, 2009, $660 million would become currently payable if we conceded all of the deductions taken through that date. We deposited a total of $320 million to defray potential interest costs associated with this disputed tax liability and may make additional deposits in 2010. As of December 31, 2009, penalties of $150 million could also become payable if the IRS is successful in its claims. If the IRS is successful in a litigated case consistent with the positions it has taken in a generic settlement offer recently proposed to us, an additional $80 million to $100 million of tax would be due for tax positions through December 31, 2009.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our business, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in increased compliance costs.

Delay in obtaining, or failure to obtain and maintain any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- ***Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other greenhouse gases produced by our fossil generation facilities*** Federal and state legislation and regulation designed to address global climate change through the reduction of greenhouse gas emissions could materially impact our fossil generation facilities. Legislation enacted in New Jersey establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities. Multiple states, primarily in the Northeastern U.S., are developing or have developed state-specific or regional legislative initiatives to stimulate CO_2 emissions reductions in the electric power industry. The RGGI began in 2009. Member states will control emissions of greenhouse gases by issuance of allowances to emit CO_2 primarily through an auction.

A significant portion of our fossil fuel-fired electric generation is located in states within the RGGI region and competes with electricity generators within PJM not located within a RGGI state. The costs or inability to purchase CO_2 allowances for our fleet operating within a RGGI state could place us at an economic disadvantage compared to our competitors not located in a RGGI state.

Potential closed-cycle cooling requirements Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs

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associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million.

If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

Remediation of environmental contamination at current or formerly owned facilities We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been deposited and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows.

In 2007, the State of New Jersey filed multiple lawsuits against parties, including us, who were alleged to be responsible for injuries to natural resources in New Jersey, including a site being remediated under our MGP program. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

More stringent air pollution control requirements in New Jersey Most of our generating facilities are located in New Jersey where restrictions are generally considered to be more stringent in comparison to other states. Therefore, there may be instances where the facilities located in New Jersey are subject to more restrictive and, therefore, more costly pollution control requirements and liability for damage to natural resources, than competing facilities in other states. Most of New Jersey has been classified as nonattainment with national ambient air quality standards for one or more air contaminants. This requires New Jersey to develop programs to reduce air emissions. Such programs can impose additional costs on us by requiring that we offset any emissions increases from new electric generators we may want to build and by setting more stringent emission limits on our facilities that run during the hottest days of the year.

Coal Ash Management Coal ash is produced as a byproduct of generation at our coal-fired facilities. We currently have a program to beneficially reuse coal ash as presently allowed by Federal and state regulations. The EPA has announced that it is reconsidering whether coal ash should be regulated, potentially as a hazardous waste. The EPA has indicated that it intends to propose a rule in early 2010. Proposed regulations which more stringently regulate coal ash, including regulating coal ash as hazardous waste, could materially increase costs at our coal-fired generation facilities. This potential regulation could also have an impact on certain of our lease investments in coal-fired generation.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-fourth of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

Storage and Disposal of Spent Nuclear Fuel We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.

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Regulatory and Legal Risk The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation.

Our nuclear generating facilities are currently operating under NRC licenses that expire in 2016, 2020, 2026, 2033 and 2034. While we have applied for extensions to these licenses for Salem and Hope Creek, the extension process can be expected to take three to five years from commencement until completion of NRC review. We cannot be sure that we will receive the requested extensions or be able to operate the facilities for all or any portion of any extended license.

Operational Risk Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides the majority of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations. For additional information, see our discussion of operational performance for all of our generation facilities below.

Nuclear Incident or Accident Risk Accidents and other unforeseen problems have occurred at nuclear stations both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, property damage and/or a change in the regulatory climate. All our nuclear units are located at one of two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Various rules have recently been implemented to respond to commodity pricing, reliability and other industry concerns. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM s locational capacity market design rules are currently being challenged in court, and FERC is currently considering changes to PJM s rules for RPM and for the Forward Capacity Market in New England. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

Many factors will affect the capacity pricing in PJM, including but not limited to:

changes in load and demand,

changes in the available amounts of demand response resources,

changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),

increases in transmission capability between zones, and changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business. Certain stakeholders, primarily consumer advocates and state commissions, have been arguing that each generating plant should be paid its as bid price rather than allowing all units to be paid a single clearing price based on the marginal unit s bid. If adopted, this change could reduce the energy payments received by certain of our generating units.

We could also be impacted by a number of other events, including regulatory or legislative actions favoring non-competitive markets and energy efficiency initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. Potential efforts in the State of New Jersey to enact a regulatory construct for the procurement of additional generation could have an impact upon the current competitive market for generation, from which we have benefited. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified by regulations.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Developers of long-distance green transmission projects currently have a number of proposed projects pending at FERC. These seek authorization for inclusion in regional transmission planning processes, with the potential to move lower-cost generation to eastern markets, including New Jersey and New York. In addition, the DOE recently awarded funding to the Eastern Interconnection Planning Collaborative (EIPC), which expects to engage in transmission planning across the Eastern Interconnection, making the construction of large-scale transmission more likely. In addition, pressures from renewable resources such as wind and solar, could increase over time, especially if government incentive programs continue to grow.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

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

Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and an impairment in the value of our power plants. Our ability to compete will also be impacted by:

- ***DSM and other efficiency efforts*** DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers usage could result in a reduction in load requirements.

Changes in technology and/or customer conservation It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, such as fuel cells, microturbines, windmills and photovoltaic (solar) cells, to a level that is competitive with that of most central station electric production. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology could also alter the channels through which retail electric customers buy electricity, which could adversely affect financial results.

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

Price fluctuations and collateral requirements We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we will be subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:

- variability in costs, such as changes in the expected price of energy and capacity that we sell into the market;
- increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market;
- the cost of fuel to generate electricity; and
- the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, 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. Therefore, significant changes in the price of natural gas will often translate into significant changes in the wholesale price of electricity. For example, during 2009, generation by our coal units was adversely affected by the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units.

Also, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2009, it may have had to provide approximately $986 million in additional collateral.

Our cost of coal and nuclear fuel may substantially increase Our coal and nuclear units have a diversified portfolio of contracts and inventory that will provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Market prices for coal and nuclear fuel have recently been volatile. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations.

Third party credit risk We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk and the amounts at stake. The impact of economic conditions may also increase such risk.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues generated by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

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Our business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability.

If the strategy we utilize to hedge our exposures to these various risks is not effective, we could incur significant losses. Our 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, customer migration and pricing differentials at various geographic locations. These cannot be predicted with certainty.

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

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and borrowings. We have significant capital requirements and continued access to debt capital from outside sources is required in order to efficiently fund the construction and other cash flow needs of our 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 have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt, financing for projects and investments or funding the equity commitments required for such projects and investments in the future.

Capital market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the capital markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. The decline in the market value of our pension assets experienced in the fourth quarter of 2008 resulted in the need to make additional contributions in 2009 to maintain our funding at sufficient levels. Further significant declines in the market value of these assets may significantly increase our funding requirements for these obligations in the future.

An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and lessen cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings. Generation by our coal units in 2009 was adversely affected by the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units. This caused a decrease in our coal unit production in 2009 compared to 2008.

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In the event of an accident or acts of war or terrorism, our insurance coverage may be insufficient if we are unable to obtain adequate coverage at commercially reasonable rates.

We have insurance for all-risk property damage including boiler and machinery coverage for our nuclear and non-nuclear generating units, replacement power and business interruption coverage for our nuclear generating units, general public liability and nuclear liability, in amounts and with deductibles that we consider appropriate.

We 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 our facilities will be sufficient.

Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

We may be unable to achieve, or continue to sustain, our expected levels of generating operating performance.

One of the key elements to achieving the results in our business plans is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, processes or management effectiveness;
- disruptions in the transmission of electricity;
- labor disputes;
- fuel supply interruptions;
- 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.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG

None.

Power and PSE&G

Not Applicable.

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ITEM 2. PROPERTIES

All of our physical property is owned by our subsidiaries. We believe that we and our 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. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

Generation Facilities

As of December 31, 2009, Power s share of summer installed generating capacity was 15,548 MW, as shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	930	100%	930	Coal/Gas	Load Following
Mercer	NJ	638	100%	638	Coal	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone(A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh(A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	526	100%	526	Coal/Oil	Base Load/Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**6,417**		**3,771**		
Nuclear:						
Hope Creek	NJ	1,199	100%	1,199	Nuclear	Base Load
Salem 1 & 2	NJ	2,345	57%	1,346	Nuclear	Base Load
Peach Bottom 2 & 3(B)	PA	2,234	50%	1,117	Nuclear	Base Load
Total Nuclear		**5,778**		**3,662**		
Combined Cycle:						
Bergen	NJ	1,178	100%	1,178	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	746	100%	746	Gas	Load Following
Guadalupe	TX	1,000	100%	1,000	Gas	Load Following
Odessa	TX	1,000	100%	1,000	Gas	Load Following
Total Combined Cycle		**5,154**		**5,154**		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	504	100%	504	Gas	Peaking
Kearny	NJ	446	100%	446	Gas	Peaking
Burlington	NJ	553	100%	553	Oil/Gas	Peaking
Linden	NJ	336	100%	336	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking

Salem	NJ	38	57%	22	Oil	Peaking
Bridgeport Harbor	CT	21	100%	21	Oil	Peaking
Total Combustion Turbine		**2,777**		**2,761**		
Pumped Storage:						
Yards Creek(C)	NJ	400	50%	200		Peaking
Total Operating Generation Plants		**20,526**		**15,548**		

(A) Operated by RRI Energy

(B) Operated by Exelon Generation

(C) Operated by JCP&L

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Energy Holdings has investments in the following generation facilities as of December 31, 2009:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
United States					
Kalaeloa	HI	208	50%	104	Oil
GWF	CA	105	50%	53	Petroleum coke
Hanford L.P. (Hanford)	CA	27	50%	13	Petroleum coke
GWF Energy					
Hanford Peaker Plant	CA	95	50%	48	Natural gas
Henrietta Peaker Plant	CA	97	50%	49	Natural gas
Tracy Peaker Plant	CA	171	50%	85	Natural gas
Total GWF Energy(A)		363		182	
Bridgewater	NH	16	40%	6	Biomass
Conemaugh	PA	15	4%	1	Hydro
Hackettstown	NJ	2	100%	2	Solar
Total United States		**736**		**361**	
International					
Turboven	Venezuela	120	50%	60	Natural gas
Turbogeneradores de Maracay (TGM)	Venezuela	40	9%	4	Natural gas
Total International		**160**		**64**	
Total Operating Power Plants		**896**		**425**	

(A) Under a Memorandum of Understanding to sell. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments.

Transmission and Distribution Facilities

As of December 31, 2009, PSE&G s electric transmission and distribution system included 23,328 circuit miles, of which 7,924 circuit miles were underground, and 822,800 poles, of which 543,313 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2009, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2009, 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 and liquefied natural gas and aggregated 2,973,000 therms (288,640,800 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**

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As of December 31, 2009, PSE&G owned and operated 17,572 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 and regulating stations, all located in New Jersey, of which 26 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.

PSE&G s First and Refunding 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. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2009, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 23,173 megavolt-amperes and 246 substations with an aggregate installed capacity of 8,062 megavolt-amperes. In addition, four substations in New Jersey having an aggregate installed capacity of 109 megavolt-amperes were operated on leased property.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

Electric Discount and Energy Competition Act (Competition Act)

In 2007, PSE&G and PSE&G Transition Funding LLC (Transition Funding) were served with a copy of a purported class action complaint (Complaint) in the Superior Court of New Jersey, Law Division challenging the constitutional validity of certain provisions of New Jersey s Competition Act, seeking injunctive relief against continued collection from PSE&G s electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. Notice of the filing of the Complaint was also provided to New Jersey s Attorney General. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional. Subsequently the same plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes, as well as recovery of such taxes previously collected, and also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same charges. We filed a motion to dismiss the amended Complaint (or in the alternative for summary judgment) and we also filed a motion with the BPU to dismiss the petition. In October 2007, our motion to dismiss the amended Complaint was granted. The plaintiff subsequently appealed this dismissal and, on February 6, 2009, the Appellate Division of the New Jersey Superior Court unanimously affirmed the lower court decision. Our motion to dismiss the BPU petition remains pending.

Con Edison (Con Ed)

In 2001, Con Ed filed a complaint with FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. Following extensive discussions, on February 23, 2009, a settlement was filed at FERC resolving all issues in the proceedings and the related proceedings at the D.C. Circuit Court of Appeals. On February 19, 2010, FERC issued an order directing the parties to address certain legal issues before determining whether the settlement can be approved. FERC also reserved the right to establish additional procedures, if needed, and indicated that it would allow further settlement discussions if the parties so desired. The final resolution of this matter cannot be predicted.

Regulatory Proceedings

RPM Auction

In May 2008, several state commissions, including the BPU and consumer advocate agencies, as well as customer groups and certain federal agencies, filed a complaint with FERC against PJM with respect to RPM.

The complaint challenged the results of the RPM capacity auctions held for the 2008/2009, 2009/2010 and 2010/2011 delivery years. It asserted that various RPM rules permitted suppliers to reduce the amount of capacity offered into the auctions, thereby increasing prices and requested that FERC find that the clearing prices produced are unlawful. FERC issued an order dismissing the complaint in September 2008, and this order was upheld on rehearing.

The BPU and the Maryland Public Service Commission have appealed these FERC orders and this appeal is pending at the U.S. Court of Appeals for the D.C. Circuit. If upheld on appeal, FERC s dismissal of the complaint eliminates the potential for the payment of refunds by suppliers, including Power, with respect to auction payments.

RPM Model

PJM FERC Filing to Prospectively Change Elements of RPM After retaining an outside consultant to prepare a report evaluating the efficacy of the RPM model, PJM submitted a filing at FERC seeking to implement certain prospective changes to RPM. Issues in this proceeding included: the cost of new entry (CONE), the integration of transmission upgrades into RPM modeling, recognition of locational capacity value, participation in RPM by demand-side and energy efficiency resources, penalties for deficiencies and unavailability of capacity resources, and the calculation of avoided cost and long-term contracting to encourage new entry. On February 9, 2009, PJM filed an Offer of Settlement with FERC on behalf of various settling parties. This Offer of Settlement proposed to, among other things, reduce cost of new entry values, eliminate the minimum offer price rule and develop seasonal capacity pricing. We filed comments in opposition to the settlement proposal. FERC issued its order with respect to the Offer of Settlement on March 26, 2009. This order was generally favorable with respect to upholding the RPM market design.

Following an additional stakeholder process that occurred after FERC issued its order, PJM made a compliance filing on September 1, 2009, proposing to implement other findings in the March 26, 2009 order. Notably, PJM proposed a CONE reset mechanism whereby the value would be adjusted annually based on an index and periodically compared against engineering studies and a statistical analysis of new entry bids. In addition, PJM proposed changes to the operation of Incremental Auctions affecting how excess capacity may be released or new capacity needs may be acquired. After FERC issued another order on October 30, 2009, PJM filed another compliance filing on December 29, 2009 in which it further modified the CONE reset mechanism by eliminating the statistical analysis of new entry bids as a benchmark. The December 29, 2009 filing also made further changes to the Incremental Auction mechanism. The changes to the Incremental Auctions are still under review by FERC and certain parties contend that more changes are required. In general, we support PJM s proposal regarding the Incremental Auctions and oppose the additional proposed changes. We cannot predict whether FERC will order additional changes to the Incremental Auction design, but we do not believe that the additional proposed changes would have significant impacts if implemented because they would not directly affect prices in the Base Residual Auction in which most capacity is cleared.

Judicial Appeals In 2007, we filed challenges to the original RPM design in the Court of Appeals for the District of Columbia Circuit relating to the manner in which the CONE was calculated under the tariff at that time. If the CONE is set too low, generators in the PJM markets may not be adequately compensated for existing capacity and may not have sufficient incentives to construct new generating units. The Court of Appeals ultimately rejected our challenge on the grounds that a back-up mechanism for setting the CONE based on engineering studies would address the problems we had identified. The method for setting CONE that was the subject of our appeal was removed from the tariff as part of the prospective changes to RPM discussed above.

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Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We 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 our 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 the 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 the 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. PSE&G s share of the remedy implementation costs is estimated at approximately $4 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. In 1996, 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 the 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) In 1996, Morton International, Inc., a subsidiary of The Dow Chemical Company, filed a lawsuit against the former customers of a former mercury refining operation located on the banks of Berry s Creek in Wood Ridge, New Jersey. The lawsuit seeks to recover cleanup costs incurred and to be incurred in remediating the site. PSE&G was among the former customers sued based on allegations that mercury originating at its Kearny Generating Station was sent to the site for refining.

(8) The EPA sent Power, PSE&G and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry s Creek in Bergen County, New Jersey and requesting that the PRPs perform a 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.

(9) In 2004, Exelon Generation signed an agreement for Peach Bottom regarding the DOE s delay in accepting spent nuclear fuel for permanent storage. Under the agreement, Exelon Generation would be reimbursed for costs previously incurred, with future costs incurred resulting from the DOE delays in accepting spent fuel to be reimbursed annually until the DOE fulfills its obligation. In addition, Exelon Generation and Power are required to reimburse the DOE for the previously received credits from the Nuclear Waste Fund. In September 2009, Power signed an agreement with the DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE s delay in accepting spent nuclear fuel for permanent disposition. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

(10) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with NJDEP Solid Waste Regulations. We have not yet determined whether the Gates landfill is located on our property or whether we have further obligations with respect to the landfill.

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

None

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PART II

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

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2009, there were 86,025 holders of record.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2004 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2004	2005	2006	2007	2008	2009
PSEG	$ 100.00	$ 130.18	$ 137.78	$ 209.33	$ 128.84	$ 153.13
S&P 500	$ 100.00	$ 104.90	$ 121.43	$ 128.09	$ 80.77	$ 102.08
DJ Utilities	$ 100.00	$ 124.95	$ 145.75	$ 174.99	$ 126.37	$ 142.06
S&P Electrics	$ 100.00	$ 117.53	$ 144.74	$ 178.14	$ 132.19	$ 136.61

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2009			
First Quarter	$33.66	$23.65	$0.3325
Second Quarter	$33.94	$27.85	$0.3325
Third Quarter	$34.02	$30.38	$0.3325
Fourth Quarter	$34.14	$29.20	$0.3325
2008			
First Quarter	$52.30	$39.08	$0.3225
Second Quarter	$47.28	$40.18	$0.3225
Third Quarter	$47.33	$31.56	$0.3225
Fourth Quarter	$33.72	$22.09	$0.3225

On February 16, 2010, our Board of Directors approved a $0.01 increase in the quarterly common stock dividend, from $0.3325 to $0.3425 per share for the first quarter of 2010. This reflects an indicated annual dividend rate of $1.37 per share.

In July 2008, our Board of Directors authorized the repurchase of up to $750 million of our common stock to be executed over 18 months beginning August 1, 2008. We repurchased 2,382,200 shares of our common stock for $92 million under this authorization. We did not repurchase any shares under this plan during 2009. The authorization expired on February 1, 2010 and has not been renewed.

The following table indicates our common share repurchases during the fourth quarter of 2009:

Fourth Quarter 2009	Total Number of Shares Purchased(A)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan(B)
				Millions
October 1-October 31		$		$ 658
November 1-November 30	2,000	$ 31.27		$ 658
December 1-December 31	48,000	$ 31.52		$ 658

(A) Represents repurchases of shares in the open market to satisfy obligations under various equity compensation award programs.

(B) Plan expired February 2010 and has not been renewed.

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The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2009:

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	4,122,050	$ 32.10	18,546,808
Equity compensation plans not approved by security holders	20,000	$ 22.93	3,709,649(A)
Total	**4,142,050**	**$ 32.06**	**22,256,457**

(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 Item 8. Financial Statements and Supplementary Data Note 17. Stock Based Compensation.

Power

We own all of Power s outstanding limited liability company membership interests. For additional information regarding Power s ability to pay dividends, see Item 7. MD&A Overview of 2009 and Future Outlook.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G s ability to continue to pay dividends, see Item 7. MD&A Overview of 2009 and Future Outlook.

On February 16, 2010, PSE&G irrevocably called, for redemption on March 22, 2010, all of its outstanding preferred stock. PSE&G deposited the redemption price and the accrued unpaid dividends to the redemption date, into Bank of New York Mellon shareholder services, terminating all rights of holders of the preferred stock except the right to receive the redemption price upon surrender of shares. As a result all of the outstanding equity is owned by PSEG.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

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

PSEG					
	2009	**2008**	**2007**	**2006**	**2005**
For the Years Ended December 31:	Millions, where applicable				
Operating Revenues	$ 12,406	$ 13,322	$ 12,677	$ 11,735	$ 11,809
Income from Continuing Operations(A)	$ 1,592	$ 983	$ 1,325	$ 673	$ 842
Net Income	$ 1,592	$ 1,188	$ 1,335	$ 739	$ 661
Earnings per Share:					
Income from Continuing Operations:					
Basic(A)	$ 3.15	$ 1.94	$ 2.61	$ 1.34	$ 1.75
Diluted(A)	$ 3.14	$ 1.93	$ 2.60	$ 1.33	$ 1.72
Net Income:					
Basic	$ 3.15	$ 2.34	$ 2.63	$ 1.47	$ 1.38
Diluted	$ 3.14	$ 2.34	$ 2.62	$ 1.46	$ 1.35
Dividends Declared per Share	$ 1.33	$ 1.29	$ 1.17	$ 1.14	$ 1.12
As of December 31:					
Total Assets	$ 28,730	$ 29,049	$ 28,299	$ 28,508	$ 29,625
Long-Term Obligations(B)	$ 7,679	$ 8,044	$ 8,709	$ 10,147	$ 11,035

(A) Income from Continuing Operations for 2008 includes an after-tax charge of $490 million related to certain leveraged leases. Income from Continuing Operations for 2006 includes an after-tax charge of $178 million related to the sale of an equity method investment.

(B) Includes capital lease obligations.

Power and PSE&G

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

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

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG s business consists of three reportable segments, which are:

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid Atlantic U.S.,

- **PSE&G,** our public utility company which provides transmission and distribution of electric energy and gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and

- **Energy Holdings,** which owns our energy-related leveraged leases and other investments.

Our business discussion in Item 1 provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. The following expands upon that discussion by describing significant events and business developments that have occurred during 2009 and key factors that we believe will drive our future performance. The following discussion refers to the Consolidated Financial Statements (Statements) and the Related Notes to Consolidated Financial Statements (Notes). This information should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2009 AND FUTURE OUTLOOK

During 2009, our business has been impacted by many factors, including lower gas prices, mild weather, the economic slowdown and increased pension costs resulting from financial market declines experienced in 2008.

The mild weather and the economic slowdown have caused an overall reduction in customer demands for electricity and gas in the markets where we operate. As a result, our generation volumes at Power in 2009 were approximately 5% lower than in 2008. This reduced volume was experienced mainly at our coal facilities as lower gas prices provided an economic advantage to gas-fired generation.

In addition to an overall reduction in customer demand during 2009, we have experienced a higher number of customers choosing to contract with independent electric suppliers rather than remain under the BGS contracts which has negatively affected Power. This migration away from BGS could be sustained or increase if energy prices continue to be lower than the energy price component of the BGS contracts. Migration has resulted and could continue to result in reduced margins as volumes that were previously sold to satisfy obligations under the BGS contracts are replaced with spot market sales at lower prices.

Our distribution operations were also impacted by both the economy and weather conditions in 2009. Our electric delivery volumes for 2009 declined by 4%, 2.5% due to the economy and 1.5% due to a cooler summer in 2009, reflecting a temperature humidity index that was 22% cooler than the summer of 2008. We experienced a 1.1% increase in our gas delivery volumes for 2009 as compared to 2008. Winter weather in 2009, as measured by heating degree days, was 2.4% higher than in 2008, resulting in 1.8% higher gas space heating demand and sales. Economic factors caused a 0.7% drop in gas sales.

Excluding the impact of weather, residential electric and gas volumes were down 0.9% and 0.2% respectively. These declines were in line with our expectations for the impact of the economy on sales to this sector. Residential sales contribute approximately 45% of our electric margin and 75% of our gas margin. Margins from Commercial and Industrial electric customers are not based on total energy consumption as measured by kilowatt-hours, but are based on fixed, monthly demand charges that are set by the highest electric demand for an hour period during the previous 12-month period or, in the case of some electric rates, by the peak demand during the current month. From May through September 2009, the number of hours exceeding 90 degrees was 67% lower than under normal summer weather conditions. This adversely impacted our billed demands,

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reducing revenues during the summer months. Commercial and Industrial gas customers also have a significant fixed component to billings. Therefore, any changes in energy usage over comparative periods may not have an equivalent effect on sales margin.

Current economic conditions have also caused deterioration in certain customer payment patterns resulting in a higher portion of our accounts receivable balances remaining outstanding for more than 180 days. This represented 14% of our total customer accounts receivable as of December 2009 as compared to 8% last year. We are focusing our efforts on the oldest and largest accounts to expedite collections. We believe we have sufficient liquidity to manage these delays in customer payments.

Looking forward, continued lower market prices and reduced demands are likely to result in lower margins for our generation business. To help offset these reduced margins we will explore growth opportunities. We have looked, and are continuing to look for ways to reduce costs while maintaining our safety, reliability and environmental standards.

There have also been significant regulatory and legislative developments during the year which may affect our operations in the future as new rules and regulations are adopted.

In March 2009, the Federal Energy Regulatory Commission (FERC) issued an order regarding PJM Interconnection LLC s (PJM) Reliability Pricing Model (RPM). The effect of this order includes an increase in the cost of new entry to more accurately reflect construction and equipment costs. This should incent both new build and continued operation of existing facilities. For additional information, see Part I, Item 3. Legal Proceedings.

In April 2009, the U.S. Supreme Court concluded that the U.S. Environmental Protection Agency (EPA) permissibly relied upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II Section 316(b) regulations of the Federal Water Pollution Control Act. This is important to us because it allows the EPA to continue to use the site-specific cost-benefit test in determining best technology available for minimizing adverse environmental impact. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

In April 2009, the EPA released a proposed finding under the Clean Air Act concluding that CO_2 is one of six types of greenhouse gases (GHG) that cause or contribute to climate change and constitute air pollution which endangers both public health and welfare. Later in 2009, the EPA proposed rules to regulate GHG from motor vehicles. When finalized, by design of the Clean Air Act, rules automatically come into effect which would subject many power generating units, including ours, to Clean Air Act permitting for GHG, including CO_2. The Clean Air Act would require an analysis of the best available control technologies (BACT) whenever a major modification is made with an associated increase in GHG emissions. The technology would have to be applied if available; however, it is unclear what EPA would consider as BACT for GHG at this time. We cannot predict the ultimate resolution of this matter, nor the effect on our operations; however any additional regulation of CO_2 emissions could affect our operations and our ability to renew permits and licenses and could result in additional material compliance costs.

In June 2009, the U.S. House of Representatives passed a bill that promotes renewable energy and requires a reduction in the emission of greenhouse gases from the majority of emission sources, including the generation sector. The bill sets forth major initiatives which include: 1) establishing a national renewable energy standard and 2) creating a market mechanism for the sale and purchase of GHG emission allowances (cap-and-trade program). If enacted in its current form, the bill could reduce or eliminate existing regional inconsistencies in GHG regulations. The Senate has not yet acted, and ultimate enactment into law of a bill with comparable provisions and rules is not certain.

In August 2009, the EPA announced that it is reconsidering whether coal ash, a by-product of generation at our coal facilities, should be regulated as a hazardous waste material. The EPA indicated that it intended to propose a rule by the end of 2009, but has not yet done so. We currently have a

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program at Hudson, Mercer and Bridgeport to beneficially reuse the coal ash as currently allowed by Federal and state regulations. Proposed regulations which more stringently regulate coal ash, including the potential regulation of coal ash as hazardous waste, could materially increase costs for our coal facilities.

During the year, various legislative proposals have been made with the intention of enacting stricter regulation over derivatives in light of the financial market issues experienced last year, largely caused by derivative trading in connection with mortgage loans. It is difficult to predict what the final legislation might contain. If the final legislation required all trading to be done over an exchange, we would expect to see our collateral requirements increase substantially to support our activities.

Our future success will also depend on our ability to respond to the challenges and opportunities presented by these and other regulatory and legislative initiatives.

Operational Excellence

While total generation volumes were down about 5% in 2009, our generating assets continued to perform well. Our lower cost nuclear generation output was 3% higher in 2009 than in 2008.

In addition, our hedging strategy has resulted in higher average realized electric prices which helped to mitigate the effect of reduced generation resulting from recent mild weather and recessionary conditions. The increase in realized prices for 2009 as compared to 2008 was due to comparably higher-priced contracts entered into in prior years that replaced older, lower-priced contracts, such as the 2005 and 2006 Basic Generation Service (BGS) auction contracts which expired in May 2008 and May 2009.

Prices set earlier in 2009 under the most recent RPM auction for the 2012-2013 period were higher than those set for the 2011-2012 period and once again varied based on the constraints in each of the PJM zones, as compared to the uniform zonal pricing set for the periods from June 2010 to May 2012.

On October 1, 2009, ownership of the Texas generation facilities was transferred from Energy Holdings to Power (See Item 8. Financial Statements and Supplementary Data Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information). Since Power had been responsible for the operation of the Texas facilities under a management agreement since January 2008, there were no operational or commercial impacts resulting from this transaction.

During 2009, PSE&G continued to demonstrate its commitment to maintaining system reliability by achieving top quartile performance in System Interruptions (SAIFI) and Customer Outage Duration (CAIDI) measures.

Energy Holdings remaining portfolio consists primarily of its lease investments at Resources and smaller equity method investments at Global, including GWF Energy which we intend to sell pending necessary approvals. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information. As a result, Energy Holdings is focused on:

- continuing to reduce our cash tax exposure related to certain leveraged leases by pursuing opportunities to terminate international leases with lessees that are willing to meet certain economic thresholds (See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information),

- earning adequate returns on its remaining investments, and

- exploring opportunities for investment in renewable energy products, including solar investments, such as those discussed below, our offshore wind project and compressed air energy storage technology.

Financial Strength

Our businesses continued to generate strong cash from operations in 2009. In addition, Power established a program for the issuance of up to $500 million of unsecured medium-term notes (MTNs) to retail investors and has issued $209 million under this program. We used these funds, cash from operations, and cash on hand to:

- contribute $364 million into our qualified pension plans in 2009,

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- pay our maturing debt obligations in 2009 (See Item 8. Financial Statements and Supplementary Data Note 13. Schedule of Consolidated Debt), including the $249 million payment of Parent debt at maturity resulting in the elimination of long term debt at Parent,

- execute a debt exchange between Power and Energy Holdings utilizing $101 million of cash on hand and $303 million of newly issued Power Senior Notes to reduce Energy Holdings Senior Notes to $127 million,

- make an additional $140 million deposit with the IRS to defray potential interest costs associated with the disputed tax liability for the leveraged lease investments, and

- redeem $280 million of non-recourse debt at our Texas plants.

The Board of Directors also approved an increase in the quarterly dividends from $0.3225 per share to $0.3325 per share of Common Stock for each quarter of 2009 resulting in an annual dividend of $1.33 per share. In February 2010, the Board of Directors approved an increase in the first quarter dividend from $0.3325 per share to $0.3425 per share of Common Stock. This increase was consistent with maintaining our target payout ratio of 40% to 50% of Operating Earnings.

We believe that our strong operations and strong financial position will continue to allow us to manage through the current economic conditions. We expect that our cash from operations, when combined with cash on hand, will be the primary source used to:

- support our projected capital expenditure program,

- fund shareholder dividends,

- fund contributions to our pension plans, and

- provide for potential payments to address income tax claims related to our leveraged lease transactions, discussed in Note 12. Commitments and Contingent Liabilities.

Any funds remaining after satisfying these obligations, when combined with potential additional financing capacity, would be discretionary cash that could be used to invest in the business or reduce debt.

Disciplined Investment

We expect to continue to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include responding to climate change, upgrading critical energy infrastructure and providing new energy supplies in markets with growing demand. We also have several projects where we are investing to continue to improve our operational performance and meet environmental commitments. During 2009:

- We were assigned construction and operating responsibility for an additional 500 kV transmission project in New Jersey that would run from Branchburg to Hudson. In December 2009, FERC granted PSE&G s request for incentive rate treatment. This project is still in the design phase and would require the receipt of numerous regulatory approvals prior to construction.

We are continuing to pursue obtaining all necessary regulatory approvals for the $750 million Susquehanna-Roseland transmission project. We are awaiting numerous regulatory approvals for this project, although on February 11, 2010, the BPU granted approval to PSE&G to construct the New Jersey portion of the project. We cannot predict the outcome of the regulatory approvals that are still pending.

We received approval from the BPU for a new solar loan program, called Solar Loan II. Under Solar Loan II, we would help finance the installation of an additional 51 MW of solar-powered generating systems in our electric service territory. The remaining financing capacity from our current solar loan program will be rolled into this new program.

The BPU approved our Solar 4 All Program. Under this program, we anticipate investing approximately $515 million to develop 80 MW of utility-owned solar photovoltaic systems over four years. Total expenditures through December 31, 2009 related to this project were approximately $13 million.

The BPU approved our Capital Economic Stimulus Program. Under this program, we anticipate accelerating $694 million of capital infrastructure investments through our distribution business in New Jersey over a 24-month period. The program seeks to support employment in New Jersey, while enhancing reliability. This program provides for a charge for contemporaneous recovery of a return on the program expenditures plus depreciation of the assets which will be adjusted each January. Total expenditures through December 31, 2009 related to this project were approximately $180 million.

The BPU approved our Energy Efficiency Economic Stimulus Program. Under this program, we anticipate approximately $190 million in energy efficiency expenditures in New Jersey over an 18-month period. The program seeks to help New Jersey meet its Energy Master Plan goal of reducing energy consumption by 20% by 2020 and to support employment growth. This program provides for a charge for contemporaneous recovery of a return on the program expenditures. Total expenditures through December 31, 2009 related to this project were approximately $5 million.

We continued construction of back end technology at our Mercer and Hudson stations and completed construction of back end technology at our Keystone station to meet our environmental commitments (see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information).

We began construction of a steam path retrofit and related upgrades at Peach Bottom with a total anticipated cost of $192 million. Approximately $27 million has been spent as of December 2009. These upgrades are expected to result in an increase of our share of capacity by 32 MW (14 MW at Unit 3 in 2011 and 18 MW at Unit 2 in 2012). We also anticipate expenditures in pursuit of additional output through an extended power uprate at Peach Bottom. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Our share of the increased capacity is expected to be 133 MW with an anticipated cost of approximately $400 million.

In connection with our exploration of new nuclear development, we continue to prepare an application for an Early Site Permit (ESP) for a new nuclear generating station to be located at the current site of the Salem and Hope Creek generating stations. We anticipate submitting the application to the NRC for the ESP in the first half of 2010. Total expenditures through December 31, 2009 related to this project were approximately $18 million.

We plan to construct 178 MW of gas-fired peaking capacity at our Kearny site. This capacity was bid and cleared the PJM RPM base residual capacity auction for the 2012-2013 period. We expect to begin construction in the second quarter of 2011. The project is expected to be in-service by June 2012. We estimate the cost of these generating units to be $160 million to $200 million, with approximately $8 million spent as of December 2009.

We also plan to construct 130 MW of gas-fired peaking capacity in Connecticut for an estimated cost of $130 million to $140 million. The project has been approved and we expect to begin construction in June 2011. The project is expected to be in service by June 2012. Total expenditures through December 2009 related to this project were $13 million.

We developed a solar project in New Jersey and have acquired two additional solar projects currently under construction in Florida and Ohio. The three together have a total capacity of approximately 29 MW. Completion of these projects is expected by the end of 2010 with a total investment of approximately $114 million.

There is no guarantee that these or future initiatives will be achieved since many issues need to be favorably resolved, such as system conditions, regulatory approvals and funding of construction or development costs.

We receive immediate recovery of our transmission investments and costs through our FERC-approved formula transmission rate. The formula rate mechanism provides for an annual setting of our transmission rates as well as an annual true up to ensure timely recovery of the actual costs of providing transmission service and PSE&G s approved return on equity. In accordance with our formula rate protocols, in October 2009, we filed our 2010 Annual Formula Rate Update with FERC. The rates became effective on January 1, 2010. On

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February 2, 2010 FERC issued an order accepting our filing. The update provides for approximately $23 million in increased revenues as part of our 2010 transmission rates.

In January 2010, we filed an updated Petition with the BPU for an increase in electric and gas distribution base rates. The amounts requested were $148 million and $74 million for electric and gas respectively. The matter is pending with a decision expected in the first half of 2010.

We anticipate that any current spending under the Capital Economic Stimulus Program will be included in our rate base with the expected decision in our Base Rate Case and that we will continue to receive contemporaneous recovery of future expenditures under this program with the return on equity adjusted to reflect the rate allowed in the Base Rate Case. The recovery mechanisms approved by the BPU for our Solar 4 All, Solar Loan, Energy Efficiency and Demand Response programs are scheduled to be reset on January 1st of each year, with the return on equity to be adjusted to reflect the rate allowed in the Base Rate Case at the time of the BPU Order.

RESULTS OF OPERATIONS

Earnings (Losses) In Millions **Years Ended December 31,**	**2009**	**2008**	**2007**
Power	$ 1,189	$ 1,115	$ 1,000
PSE&G	325	364	380
Energy Holdings(A)	72	(468)	12
Other(B)	6	(28)	(67)
PSEG Income from Continuing Operations	**1,592**	**983**	**1,325**
Income from Discontinued Operations, Including Gain on Disposal(C)		205	10
PSEG Net Income	**$ 1,592**	**$ 1,188**	**$ 1,335**

Earnings Per Share (Diluted) Years Ended December 31,	**2009**	**2008**	**2007**
PSEG Income from Continuing Operations	**$ 3.14**	**$ 1.93**	**$ 2.60**
Income from Discontinued Operations, Including Gain on Disposal(C)		0.41	0.02
PSEG Net Income	**$ 3.14**	**$ 2.34**	**$ 2.62**

(A) Energy Holdings results include after-tax charges of $490 million taken in 2008 related to leveraged lease transactions, the reversal of $29 million, after-tax, of that reserve in 2009 and $23 million of after-tax loss resulting from the sale of Chilquinta and Luz del Sur (LDS) in 2007.

(B) Other includes parent company interest and financing costs, donations, certain administrative and general expenses and certain consolidating entries related to the debt exchange between Power and Energy Holdings.

(C) See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments.

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Our results include the realized gains, losses and earnings on Power s NDT Funds and other related activity. This includes the net realized gains and other-than-temporary impairments, as well as interest and dividend income and other costs related to the NDT Funds which are recorded in Other Income and Deductions. This also includes the interest accretion expense on Power s nuclear asset retirement obligation, which is recorded in Operation and Maintenance Expense and the Depreciation expense related to the asset retirement obligation. The combined after-tax impact on earnings of this activity for the years ended December 31, 2009, 2008 and 2007 is shown in the chart below along with the after-tax impacts of mark-to-market (MTM) activity:

	In Millions, after tax		
	2009	**2008**	**2007**
NDT Fund Activity	$ 9	$ (71)	$ 12
Non-Trading Mark-to-Market Gains (Losses)	$ (25)	$ 16	$ 10

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding changes related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, donations and general and administrative costs at the parent company. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data Note 22. Related-Party Transactions.

	For the Years Ended December 31,			**Increase / (Decrease) 2009 vs 2008**		**Increase / (Decrease) 2008 vs 2007**	
	2009	**2008**	**2007**				
		Millions		Millions	%	Millions	%
Operating Revenues	$ 12,406	$ 13,322	$ 12,677	$ (916)	(7)	$ 645	5
Energy Costs	5,711	7,295	6,512	(1,584)	(22)	783	12
Operation and Maintenance	2,603	2,486	2,406	117	5	80	3
Depreciation and Amortization	838	792	774	46	6	18	2
Income from Equity Method Investments	39	37	115	2	5	(78)	(68)
Gain (Loss) on Disposal of and (Impairment) on Equity Method Investments	(22)	(27)	137	5	(19)	(164)	N/A
Other Income and Deductions	86	100	91	(14)	(14)	9	10
Other-Than-Temporary Impairments	61	220	73	(159)	(72)	147	201
Interest Expense	527	594	727	(67)	(11)	(133)	(18)
Income Tax Expense	1,044	926	1,064	118	13	(138)	(13)
Income from Discontinued Operations, including Gain on Disposal, net of tax		205	10	(205)	(100)	195	N/A

The 2009 year-over-year increase in our Income from Continuing Operations reflects the following:

Absence of after-tax charges of $490 million recorded in 2008 associated with deductions taken for tax purposes on certain types of leveraged lease transactions at Energy Holdings that are being challenged by the IRS. See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information.

Earnings were higher at Power due to lower other than temporary impairments on investments in the NDT Funds, higher prices realized under sales contracts and lower generation costs, and lower interest expense, partially offset by lower sales volumes, higher depreciation expense and higher pension expense.

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Earnings were higher at Energy Holdings due to gains on sales and terminations of leveraged lease assets, partially offset by lower income due to assets sold.

Earnings were lower at PSE&G due primarily to lower customer demand and higher pension expense.

For a detailed explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings below.

Power

As discussed in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, Power s results have been retrospectively adjusted to include the earnings related to Texas for prior periods.

	For the Years Ended December 31,			**Increase / (Decrease)**	**Increase / (Decrease)**
	2009	**2008**	**2007**	**2009 vs 2008**	**2008 vs 2007**
			Millions		
Income from Continuing Operations	$ 1,189	$ 1,115	$ 1,000	$ 74	$ 115
Loss from Discontinued Operations, net of tax			(8)		(8)
Net Income	$ 1,189	$ 1,115	$ 992	$ 74	$ 107

For the year ended December 31, 2009, the primary reasons for the increase in Income from Continuing Operations were

- lower fuel costs and higher pricing under our BGS and other contracts partially offset by lower generation,
- lower other-than-temporary impairments and lower net losses on investments in the NDT Funds,
- lower maintenance costs due to higher planned outage work in 2008 partially offset by higher pension costs in 2009, and
- lower interest expense due to higher capitalization of interest related to projects in 2009,
- partially offset by higher depreciation due to additional assets placed in service in 2009.

Included is the recognition of non-trading MTM losses of $25 million, after-tax, in 2009 as compared to $16 million of after-tax MTM gains in 2008.

For the year ended December 31, 2008, the primary reasons for the increase in Income from Continuing Operations were higher prices and sales volumes on BGS contracts and in the various power pools, partially offset by higher generation costs, and

higher prices on a reduced sales volume under the BGSS contract due to customer conservation and a milder winter heating season in 2008,

partially offset by net losses on investments in the NDT Funds.

Included is the recognition of non-trading MTM gains of $16 million, after-tax, in 2008 as compared to $10 million of after-tax MTM gains in 2007.

The year-over-year detail for these variances for these periods is discussed below:

	For the Years Ended December 31,			**Increase / (Decrease)**		**Increase / (Decrease)**	
Power	**2009**	**2008**	**2007**	**2009 vs 2008**		**2008 vs 2007**	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 7,143	$ 8,483	$ 7,422	$ (1,340)	(16)	$ 1,061	14
Energy Costs	3,740	5,051	4,414	(1,311)	(26)	637	14
Operation and Maintenance	1,114	1,126	1,061	$ (12)	(1)	$ 65	6
Depreciation and Amortization	203	181	158	22	12	23	15
Other Income and (Deductions)	99	100	145	$ (1)	(1)	$ (45)	(31)
Other-Than -Temporary Impairments	60	219	73	(159)	(73)	146	200
Interest Expense	167	192	185	$ (25)	(13)	$ 7	4
Income Tax Expense	769	699	676	70	10	23	3
Loss from Discontinued Operations, net of tax			(8)	$	N/A	$ 8	100

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For the year ended December 31, 2009 as compared to 2008

Operating Revenues decreased $1,340 million due to

Generation revenues decreased $733 million due to

- lower revenues of $609 million resulting from lower volumes of generation sold at lower prices in PJM, ERCOT and the NY power pool and lower prices on a higher volume of generation sold in the ISO-NE, partially offset by favorable results from financial hedging transactions,
- a net decrease of $146 million due to a lower volume of BGS contracts partially offset by higher prices, and
- a decrease of $51 million due to lower ancillary services revenues and auction revenue rights as well as the absence of a damage claim awarded by the federal government in 2008,
- partially offset by higher revenues of $60 million due to several new wholesale contracts entered into in 2009 and repricing of certain wholesale contracts, and
- $14 million of higher capacity payments largely due to changes in PJM s capacity market.

Gas Supply revenues decreased $622 million

- including a net decrease of $436 million resulting from sales under the BGSS contract, substantially comprised of lower average gas prices in 2009 net of gains on financial hedging transactions on a volume of sales nearly unchanged from that in 2008, and
- a net decrease of $186 million due to lower prices on a reduced sales volume to third party customers.

Trading revenues increased $15 million due primarily to gains on electric-related contracts.

Operating Expenses

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. Energy Costs decreased by $1,311 million due to

- **Generation costs** decreased by $696 million due to $952 million of lower fossil fuel costs, primarily reflecting lower average natural gas prices and lower volumes of natural gas and coal purchases, partly offset by $21 million of higher nuclear fuel costs, net losses of $110 million from financial hedging transactions, $44 million for increased power purchases, \$33 million for CO_2 allowances and environmental technology and fees, \$18 million for higher purchases of financial transmission rights and \$16 million for cancellation charges on cancelled coal shipments.

- **Gas costs** decreased \$615 million, reflecting net decreases of \$434 million and \$181million related to Power s obligations under the BGSS contract and sales to third party customers respectively, reflecting lower inventory costs.

Operation and Maintenance decreased \$12 million due primarily to

- a net decrease of \$85 million due to lower planned maintenance costs and the absence of expense for planned outages in 2008 at our fossil stations,
- partially offset by \$19 million related to additional staffing and salary increases, a planned outage at Peach Bottom and Hope Creek in 2009 and preventative maintenance costs at all our nuclear stations, and
- an increase in pension expense of \$55 million.

Depreciation and Amortization increased \$22 million due to

- an increase of \$18 million due to pollution control equipment being placed into service in December 2008 at our Mercer 1 and 2 generating facilities and in October 2009 at our Keystone generating facility, and

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- an increase of $10 million resulting from larger depreciable asset bases for fossil and nuclear in 2009,
- partially offset by a $4 million related to the reimbursement of previously capitalized storage costs for spent nuclear fuel resulting from a favorable settlement in September 2009 for reimbursement of such costs by the U.S. Department of Energy.

Other Income and Deductions Net Other Income decreased $1 million due primarily to

a decrease of $8 million in interest income, dividends and fees related to the NDT Funds, and

a write-off of $5 million due to the early retirement of obsolete pollution control equipment,

partially offset by an increase in net gains of $14 million on the NDT Fund securities.

Other-Than-Temporary Impairments decreased $159 million due to the lower charges in 2009 related to the NDT Fund securities.

Interest Expense decreased $25 million due to

higher capitalized interest of $14 million in 2009 due primarily to installation of back-end pollution-control technology at Fossil and projects at Nuclear in 2009, and

lower interest expense of $29 million due to the maturity of $250 million of 3.75% Notes in April 2009 and redemption of Texas project loans in February 2009,

partially offset by $17 million of higher interest expense in 2009 related to the issuance of $209 million of medium-term notes in January 2009 and $303 million of notes issued in September 2009 as part of a debt exchange with Energy Holdings.

Income Tax Expense increased $70 million in 2009 due primarily to

an increase of $59 million due to higher pre-tax income and $17 million due to higher earnings from the NDT Funds,

$22 million due to decreased benefits from a manufacturing deduction under the American Jobs Creation Act of 2004, and $10 million due to an increase in state taxes,

partially offset by $32 million from the reduction of the reserve for uncertain tax positions and $6 million related to prior years book versus tax return timing adjustments.

For the year ended December 31, 2008 as compared to 2007

Operating Revenues increased $1,061 million due to

Generation revenues increased $882 million due to

¡ higher revenues of $446 million resulting from a higher volume of generation being sold at higher prices into PJM and ISO-NE and higher prices on lower volumes of sales in ERCOT and the New York power pools, partially offset by net losses on financial hedging transactions,

¡ a net increase of $355 million from higher prices on a higher volume of BGS contracts modestly offset by the expiration of several contracts in May 2008,

¡ $67 million from higher capacity prices resulting from the changes in the capacity markets in PJM, New York and Connecticut, and

¡ $32 million for ancillary and other services as well as a damage claim awarded by the federal government for an oil spill in the Delaware River in 2004.

Gas Supply revenues increased $156 million

¡ including $130 million resulting from sales under the BGSS contract due to higher average gas prices in 2008, partly offset by lower sales volumes due to customer conservation and milder winter temperatures in 2008, and

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- a net increase of $27 million due to higher prices on sales to third party customers on a reduced sales volume.

Trading revenues increased $23 million principally due to gains on electric-related contracts and contracts related to financial transmission rights.

Operating Expenses

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. Energy Costs increased by $637 million due to

- **Generation costs** increased by $466 million due to $509 million of higher fuel costs related to higher prices and higher volumes of natural gas and $17 million of higher costs of energy purchases reflecting higher prices, partly offset by net gains of $67 million from financial hedging transactions.

- **Gas costs** increased $171 million, reflecting net increases of $150 million and $20 million related to Power s obligations under the BGSS contract and sales to third party customers, respectively, reflecting higher inventory costs partially offset by reduced volumes.

Operation and Maintenance increased $65 million due primarily to

- a net increase of $49 million due to planned outages and higher maintenance costs at our fossil stations, primarily Hudson and Linden,

- an increase of $10 million related to planned outages at the Peach Bottom and Salem stations, and

- an increase of $6 million in asset management fees and salaries at the Texas plants.

Depreciation and Amortization increased $23 million due to

- an increase of $14 million resulting from a larger depreciable nuclear and fossil asset base in 2008, and

- an increase of $9 million due to depreciation of pollution control equipment being placed into service at our Bridgeport generating facility.

Other Income and Deductions Net Other Income decreased $45 million due to

net losses of $19 million on the NDT Fund derivative instruments,

- lower interest income of $13 million from short-term loans to our parent company, and
- a $13 million charge for the purchase of net operating loss carryforwards under the State of New Jersey Tax Benefit Purchase Program.

Other Than Temporary Impairments increased $146 million related to the NDT Fund securities.

Interest Expense increased $7 million due primarily to the issuance of $40 million of 5.75% Pollution Control Bonds due 2037 in November 2007 and $44 million of 4.00% Pollution Control Bonds due 2042 in December 2007.

Income Tax Expense increased $23 million in 2008 due primarily to

- an increase of $53 million due to higher pre-tax income,
- partially offset by a reduction of $16 million due to lower earnings from the NDT Funds, and
- a reduction of $9 million due to increased benefits from a manufacturing deduction under the American Jobs Creation Act of 2004.

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PSE&G

	For the Years Ended December 31,			Increase / (Decrease)	Increase / (Decrease)
	2009	2008	2007	2009 vs 2008	2008 vs 2007
			Millions		
Income from Continuing Operations	$ 325	$ 364	$ 380	$ (39)	$ (16)
Net Income	$ 325	$ 364	$ 380	$ (39)	$ (16)

For the year ended December 31, 2009, the primary reasons for the decrease in Income from Continuing Operations were

lower revenues due to lower customer demand resulting from current economic conditions, and

higher Operation and Maintenance expense, primarily increased pension expense,

partially offset by a transmission formula rate increase.

For the year ended December 31, 2008, the primary reasons for the decrease in Income from Continuing Operations were

lower revenues due to lower customer demand resulting from current economic conditions, and

lower electric and gas sales volumes due to a milder winter heating season,

partially offset by tax adjustments related to an IRS refund and other tax items.

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

PSE&G	For the Years Ended December 31, 2009	2008	2007	Increase / (Decrease) 2009 vs 2008		Increase / (Decrease) 2008 vs 2007	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 8,243	$ 9,038	$ 8,493	$ (795)	(9)	$ 545	6
Energy Costs	5,170	6,072	5,498	(902)	(15)	574	10
Operation and Maintenance	1,474	1,338	1,308	136	10	30	2
Depreciation and Amortization	608	583	591	25	4	(8)	(1)
Other Income and (Deductions)	5	8	12	(3)	(38)	(4)	(33)
Interest Expense	312	325	332	(13)	(4)	(7)	(2)
Income Tax Expense	226	228	257	(2)	(1)	(29)	(11)

For the year ended December 31, 2009 as compared to 2008

Operating Revenues decreased $795 million due primarily to

Delivery Revenues increased $30 million due primarily to an increase in prices for electric distribution and transmission partially offset by a decrease in electric distribution. Gas distribution was up due to both higher volumes and lower prices.

Electric distribution revenues were down $23 million due primarily to lower sales volumes of $63 million partially offset by rate increases of $40 million. The volumes were down due to weather and economic conditions. The current economic slowdown reduced volumes as customers cut back on use of air conditioning to save money. Rates were up due to an increase in Regional Greenhouse Gas Initiative (RGGI) revenues and stimulus rates.

Transmission revenues were up $37 million due primarily to net rate increases.

Gas distribution revenues were up $16 million due to higher sales volumes of $6 million, RGGI revenues of $4 million and stimulus rates of $6 million.

Other Operating Revenues increased $10 million due primarily due an increase in our appliance repair business.

Clause Revenue, primarily the Societal Benefits Charges (SBC), increased $67 million, which is entirely offset by the amortization of related costs (Regulatory Assets) into the Operation and Maintenance accounts, and the Depreciation and Amortization accounts. PSE&G earns no margins on SBC collections. For more information, see the discussion of State Regulation in Part I, Item 1 Regulatory Issues.

Commodity Revenue decreased $902 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy costs. PSE&G earns no margin on the provision of BGS and BGSS.

Electric revenues decreased $479 million primarily due to $355 million in lower BGS revenues, and $167 million in lower non-utility generation (NUG) revenue due primarily to lower prices, partially offset by $43 million in higher NGC revenue. BGS sales were down 14% primarily due to large customer migration to Third Party Suppliers (TPS), in contrast delivery sales were only down 4% due to the weather and economic conditions.

Gas revenues decreased $423 million due to decreased BGSS prices $365 million and lower commercial and industrial sales due to economic conditions $70 million, offset by higher sales to residential customers $12 million. The average price of gas was 16% lower in 2009 than 2008.

Energy Costs decreased $902 million. This is entirely offset by Commodity revenue. Details are as follows:

Gas costs decreased $423 million due to $365 million or 16% in lower prices and by $58 million or 3% in lower sales volumes due primarily to economic conditions.

Electric costs decreased $479 million due to $487 million or 13% in lower BGS and NUG volumes due to large customer migration to TPS, weather and economic conditions offset by $8 million in higher BGS and NUG prices.

Operation and Maintenance increased $136 million primarily due to

$69 million of higher labor and benefits, primarily increased pension expense,

increases in electric and gas SBC expenses of $61 million, and

higher expenses related to RGGI and Capital Adjustment Charges (CAC) of $21 million,

partially offset by lower material usage of $11 million and a lower gas bad debt expense of $3 million.

Depreciation and Amortization increased $25 million due to

increases of $12 million for amortization of regulatory assets,

$8 million additional plant in service, and $5 million in software amortization.

Other Income and Deductions Net Other Income decreased $3 million due to $4 million in lower investment income resulting from current market conditions, partially offset by a $1 million in solar loan interest.

Interest Expense decreased by $13 million due primarily to lower average debt balances.

Income Tax Expense decreased by $2 million due primarily to lower pretax income, offset by $17 million tax benefits taken in 2008 related to an IRS refund.

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For the year ended December 31, 2008 as compared to 2007

Operating Revenues increased $545 million due primarily to

Delivery Revenues decreased $40 million due primarily to an lower sales volumes for electric distribution, transmission and gas distribution.

- Electric distribution revenues were down $22 million due primarily to lower sales volumes of $31 million partially offset by rate increases of $9 million. The volumes were down due to mild weather and economic conditions.
- Transmission revenues were down $13 million due a lower transmission peak offset by a rate increase of $4 million.
- Gas distribution revenues were down $9 million due to lower sales volumes resulting from mild weather and economic conditions.

Other Operating Revenues decreased $6 million primarily due to lower appliance service sales.

Clause Revenue, primarily the SBC, increased $17 million, which is entirely offset by the amortization of related costs (Regulatory Assets) into the Operation and Maintenance accounts, and also into the Depreciation and Amortization accounts. PSE&G earns no margins on SBC collections. For more information, see the discussion of State Regulation in Part I, Item 1 Regulatory Issues.

Commodity Revenue increased $574 million due to higher Electric and Gas revenues. This is entirely offset as savings in Energy costs. PSE&G earns no margin on the provision of BGS and BGSS.

- Electric revenues increased $432 million primarily due to $491 million in higher prices for BGS, and $75 million in higher NUG prices, partially offset by $112 million for lower BGS volumes, and $21 million due to lower NUG volumes and lower NGC prices.
- Gas revenues increased $142 million due to $234 million for increased BGSS prices offset by $92 in lower sales volumes due to weather and economic conditions.

Energy Costs increased $574 million. This is entirely offset by Commodity revenue.

- Gas costs increased $142 million due to $234 million or 9% in higher prices partially offset by $92 million or 4% in lower sales volumes due to weather and economic conditions.
- Electric costs increased $432 million due to 17% in higher prices for BGS and NUG purchases $552 million, partially offset by 4% in lower BGS volumes due to weather and economic conditions $121 million.

Operation and Maintenance increased $30 million primarily due to

- increases in electric SBC expenses of $42 million offset by lower gas SBC expenses $6 million, and
- higher bad debt expense $8 million,

partially offset by lower injuries and damages of $8 million, and

decreased payroll and fringe benefits $8 million.

Depreciation and Amortization decreased $8 million due to

decrease of $10 million for amortization of regulatory assets,

$5 million in software amortization, and

$5 million in amortization of DOE enrichment facility decommissioning costs,

partially offset by $12 million additional plant in service.

Other Income and Deductions Net Other Income decreased $4 million due to

$7 million in lower investment income due to market conditions,

partially offset by a $3 reduction in income tax on contributions in aid of construction (CIAC).

Interest Expense decreased by $7 million due primarily to lower average debt balances.

Income Tax Expense decreased by $29 million due primarily to $18 million on lower pretax income, and $17 million tax benefits related to an IRS refund.

Energy Holdings

	For the Years Ended December 31, 2009	2008	2007	Increase / (Decrease) 2009 vs 2008	Increase / (Decrease) 2008 vs 2007
			Millions		
Income (Loss) from Continuing Operations	$ 72	$ (468)	$ 12	$ 540	$ (480)
Income from Discontinued Operations, including Gain on Disposal, net of tax		205	18	(205)	187
Net Income (Loss)	$ 72	$ (263)	$ 30	$ 335	$ (293)

For the year ended December 31, 2009, the primary reasons for the increase in Income from Continuing Operations were

- the absence of a $490 million, after-tax, charge on leveraged leases in 2008 and the reduction of $29 million, after-tax, of that reserve in 2009, and
- gains on the sales and terminations of leveraged lease assets,
- partially offset by lower leveraged lease revenues due primarily to the sale of leveraged lease assets,
- the premium paid on the debt exchange with Power, and
- the absence of benefits recorded in 2008 related to an IRS refund claim.

For the year ended December 31, 2008, the primary reasons for the decrease in Income from Continuing Operations were

- the charge on leveraged leases recorded in the second quarter in 2008, and
- the absence of income from Chilquinta and LDS which were sold in 2007,
- partially offset by lower interest expense due to debt retirement and lower premium on bond redemption, and

tax adjustments related to an IRS refund.

The year-over-year detail for these variances for these periods is below:

Energy Holdings	**For the Years Ended 2009**	**2008**	**2007**	**Increase / (Decrease) 2009 vs 2008**		**Increase / (Decrease) 2008 vs 2007**	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 221	$ (368)	$ 167	$ 589	N/A	$ (535)	N/A
Operation and Maintenance	47	57	66	(10)	(18)	(9)	(14)
Depreciation and Amortization	11	11	12			(1)	(8)
Income from Equity Method Investments	39	36	115	3	8	(79)	(69)
Gain (Loss) on Disposal of and (Impairment) on Equity Method Investments	(22)	(27)	137	(5)	(19)	(164)	N/A
Other Income and (Deductions)	(27)	25	(28)	(52)	N/A	53	N/A
Interest Expense	37	57	125	(20)	(35)	(68)	(54)
Income Tax Expense	45	9	176	36	N/A	(167)	N/A
Income from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	$	$ 205	$ 18	$ (205)	(100)	$ 187	N/A

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For the year ended December 31, 2009 as compared to 2008

Operating Revenues increased $589 million due primarily to

- the absence of a $485 million charge on leveraged leases in 2008, and

- a $158 million increase due to sales and terminations of leveraged lease assets and other investments,

- partially offset by lower leveraged lease revenues of $29 million due primarily to the sale of leveraged lease assets and

- a $25 million charge recorded in December 2009 due to a change in the timing of projected cash flows related to our leveraged leases.

See Note 12. Commitments and Contingent Liabilities for additional information.

Operation and Maintenance decreased $10 million due primarily to lower outside service costs, wages, salaries and benefits.

Income from Equity Method Investments experienced no material change.

Gain (Loss) on Disposal of and Impairment on Equity Method Investments Net impairments decreased $5 million due to the absence of the impairment on PPN recorded in 2008 which was partially offset by the impairment of GWF in 2009.

Other Income and (Deductions) Net Other Deductions increased $52 million due primarily to a premium paid on the debt exchange with Power.

Interest Expense decreased $20 million due primarily to lower debt balances following the debt exchange with Power.

Income Tax Expense increased $36 million due primarily to $93 million related to the sale of leverage lease and other assets in 2009, partially offset by a $57 million decrease on the reserve for unrecognized taxes.

Income from Discontinued Operations, including Gains on Disposal, net of tax

During 2008, we sold our investments in SAESA Group and Bioenergie. Income from Discontinued Operations relating to these investments for the year ended December 31, 2008 totaled $205 million. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information.

For the year ended December 31, 2008 as compared to 2007

Operating Revenues decreased $535 million due primarily to

- a $485 million charge on leveraged leases in 2008, and

- a $38 million decrease in leveraged lease income, due to lease adjustments.

Operation and Maintenance decreased $9 million due primarily to lower outside service costs, wages, salaries and benefits.

Depreciation and Amortization experienced no material change.

Income from Equity Method Investments decreased $79 million due primarily to

- the absence of earnings of $65 million from Chilquinta and LDS which were sold in 2007, and
- $7 million in lower income from GWF due to higher fuel costs and lower generation.

Gain (Loss) on Disposal of and Impairment on Equity Method Investments decreased $164 million due to

- the absence of $153 million pre-tax gain on the sale of equity investments in 2007, and
- $11 million in higher write-downs of investment in PPN and Turboven in 2008 as compared to 2007.

Other Income and (Deductions) Net Other Income increased $53 million due primarily to

- the absence of a $46 million loss on the early retirement of debt resulting from the December 2007 redemption of Energy Holdings 10% Senior Notes due 2009, and
- $6 million of higher interest and dividend income.

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Interest Expense decreased $68 million due primarily to lower debt balances.

Income Tax Expense decreased $167 million due primarily to

- the absence of $163 million of taxes recorded as a result of the sale of Chilquinta and LDS in 2007, and
- $37 million of lower adjustments to the reserve for unrecognized tax benefits,
- partially offset by $14 million in higher taxes on pre-tax income and $18 million of federal and state audit adjustments for prior years paid in 2008.

Income from Discontinued Operations, including Gains on Disposal, net of tax

During 2008, we sold our investments in SAESA Group and Bioenergie. During 2007, we sold our investment in Electroandes. Income from Discontinued Operations relating to these investments for the years ended December 31, 2008 and December 31, 2007 totaled $205 million and $18 million, respectively. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Financing Methodology

Our capital requirements are met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt and equity for capital investments.

PSE&G s sources of external liquidity include a $600 million multi-year syndicated credit facility as well as bilateral credit agreements. PSE&G s $600 million commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending with PSEG or any other affiliate. PSE&G s dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain solid investment grade credit ratings. PSE&G s long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Energy Holdings has historically lent to the money pool; its primary source of liquidity is its invested balance with PSEG. PSEG s sources of external liquidity include a $1.0 billion multi-year syndicated credit facility as well as bilateral credit agreements. These facilities are available to back-stop PSEG s $1.0 billion commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to Power for the issuance of letters of credit. PSEG s credit facilities and the $1 billion commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power s sources of external liquidity include $1.95 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of hedging activities and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power s dividend payments to the parent are also designed to be consistent with its capital structure objectives which have been established to achieve solid investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues either retail medium-term notes or senior unsecured debt to raise long-term capital.

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Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2009, our operating cash flow decreased by $490 million. For the year ended December 31, 2008, our operating cash flow increased by $424 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power s operating cash flow decreased $148 million from $1,806 million to $1,658 million for the year ended December 31, 2009, as compared to 2008, primarily resulting from

- a decrease of $350 million in net cash collateral receipts,
- a decrease of $144 million from net payments of counterparty payables,
- $94 million in increased pension fund contributions and related payments in 2009,
- partially offset by a $260 million net decrease in spending on fuel inventories resulting from reduced pricing and demands,
- a $103 million increase from net collections of counterparty receivables, and
- a $69 million increase in deferred income taxes due to bonus depreciation and an increase in planned pension contributions.

Power s operating cash flow increased $541 million from $1,265 million to $1,806 million for the year ended December 31, 2008, as compared to 2007, primarily resulting from

- an increase of $400 million in net cash collateral receipts,
- an increase of $113 million from net collections of counterparty receivables, and
- an increase in net income of $123 million, which includes $163 million of higher net losses in 2008 as compared to 2007,
- partially offset by a $201 million net increase in spending on fuel inventories resulting from reduced pricing and demands.

PSE&G

PSE&G s operating cash flow increased $44 million from $913 million to $957 million for the year ended December 31, 2009, as compared to 2008, due primarily to

$171 million in higher collections of customer receivables,

increases of $108 million in deferred income taxes related to bonus depreciation and increased planned pension contributions, and

$90 million in higher recovery of deferred energy costs,

partially offset by $180 million in increased pension fund contributions and related payments,

decreases of $94 million in accounts payable and obligation to return cash collateral due primarily to lower electric and gas payables, and

$53 million in higher prepaid state sales taxes.

PSE&G s operating cash flow increased $235 million from $678 million to $913 million for the year ended December 31, 2008, as compared to 2007, due primarily to

$199 million in higher collections of customer receivables,

a $164 million increase in deferred income taxes due to bonus depreciation and increased planned pension contributions, partially offset by decreases of $122 million in accounts payable due primarily to lower electric and gas payables, and

$39 million in increased pension fund contributions and related payments.

Energy Holdings

Energy Holdings operating cash flow decreased $373 million for the year ended December 31, 2009, as compared to 2008. The decrease was mainly attributable to tax payments related to the termination of leveraged lease investments in 2009, which were higher than tax payments made in 2008 related to asset sales. In addition, Energy Holdings made a $140 million tax deposit with the IRS in 2009 compared to a tax deposit of $80 million in 2008. Proceeds from the termination of leveraged leases in 2009 and the sale of investments in 2008 is reflected in our cash flows related to investing activities.

Energy Holdings operating cash flow decreased $441 million for the year ended December 31, 2008, as compared to 2007. The decrease was mainly attributable to increased tax payments in 2008.

Short-Term Liquidity

We have been managing our sources of liquidity in an effort to assure that we continue to have sufficient access to cash to operate our businesses in the event the capital markets do not allow for near-term financing at reasonable terms. We also monitor the financial condition and concentration of lenders in our bank facilities. There is no provision in any of our credit facilities that would require lenders in that facility to assume the loan commitments of any other financial institution that fails to meet its loan commitments. As of December 31, 2009, no single institution represented more than 11% of the commitments in our credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries liquidity needs. Our total credit facilities and available liquidity as of December 31, 2009 were as follows:

	As of December 31, 2009		
Company/Facility	**Total Facility**	**Usage(A)**	**Liquidity Available**
		Millions	
PSEG	$ 1,000	$ 523	$ 477
Power	2,050	159	1,891
PSE&G	600		600
Total	**$ 3,650**	**$ 682**	**$ 2,968**

(A) Usage does not include $26 million borrowed under PSEG s uncommitted bilateral agreement.

In July 2009, Power entered into a new $350 million syndicated credit facility that expires in July 2011. This new facility is available for funding the obligations of Power and its subsidiaries. Also in July 2009, Energy Holdings terminated its $136 million syndicated credit facility. As noted above, the PSEG credit facilities can be used to support subsidiary liquidity needs, including those of Energy Holdings.

In September 2009, a $50 million bilateral credit facility and a $150 million bilateral credit facility expired at Power. In March 2010, a $100 million of bilateral credit facility at Power is scheduled to expire. We review our liquidity requirements on a regular basis. As of December 31, 2009, our total credit facility capacity was in excess of our anticipated maximum liquidity requirements through 2010. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities and Note 13. Schedule of Consolidated Debt. Given current economic conditions, no assurances can be given that we will be able to replace expiring facilities on commercially reasonable terms.

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Long-Term Debt Financing

PSEG and Power have no debt maturities scheduled in 2010. PSE&G has $300 million of a debt maturity upcoming in 2010 excluding securitized debt. This maturity will occur during the first quarter of 2010. We believe that we will be able to refinance or retire this obligation given our current financial position and demonstrated continued access to the capital markets.

For a discussion of our long-term debt transactions during 2009 and into 2010, see Item 8. Financial Statements and Supplementary Data Note 13. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements may contain maximum debt to equity ratios, minimum cash flow tests and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

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, 2009, PSE&G s Mortgage coverage ratio was 4.0 to 1 and the Mortgage would permit up to approximately $2.8 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company s agreement. We have not defaulted under these agreements.

PSEG s bank credit agreement contains cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreement, it would be an event of default if both Power and PSE&G cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in Power s or PSE&G s credit agreements or indentures.

Ratings Triggers

Our debt indentures and credit agreements 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. In the event that we are not able to affirm representations and warranties on credit agreements, lenders are not required to make loans.

Fluctuations in commodity prices or a deterioration of Power s credit rating to below investment grade could increase Power s required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today s market prices. See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for further information.

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

PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G s other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

Common Stock Dividends and Repurchases

Dividend payments on common stock for the year ended December 31, 2009 were $1.33 per share and totaled $673 million. Dividend payments on common stock for the year ended December 31, 2008 were $1.29 per share and totaled $655 million.

In July 2008, our Board of Directors authorized the repurchase of up to $750 million of our common stock to be executed over 18 months beginning August 1, 2008. We repurchased 2,382,200 shares of our common stock for $92 million under this authorization. We did not repurchase any shares under this authorization during 2009. The authorization expired on February 1, 2010 and has not been renewed.

On February 16, 2010, our Board of Directors approved a $0.01 increase in our quarterly common stock dividend, from $0.3325 to $0.3425 per share for the first quarter of 2010. This reflects an indicated annual dividend rate of $1.37 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our business, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may have a material adverse effect on the market price of our securities and serve to increase our cost of capital and limit our access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that any of our 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 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. In March 2009, S&P affirmed the ratings and outlooks of PSEG, Power and PSE&G. In June 2009, Fitch affirmed the ratings and outlooks of PSEG, Power and PSE&G. In August, Moody s upgraded the majority of senior secured debt ratings for investment grade regulated utilities. As a result, PSE&G s senior secured rating (Mortgage Bonds) improved from A3 to A2. In September and October, Moody s published updated credit opinions for PSE&G, Power and PSEG which kept the ratings and outlooks unchanged.

	Moody s(A)	S&P(B)	Fitch(C)
PSEG:			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power:			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB	BBB+
PSE&G:			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	A2	A	A
Commercial Paper	P2	A2	F2

(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.

(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

For the year ended December 31, 2009, we had Other Comprehensive Income of $61 million on a consolidated basis. Other Comprehensive Income was due primarily to $73 million of net unrealized gains related to the NDT Funds and $8 million of unrealized gains on derivative contracts accounted for as hedges, partially offset by a $29 million increase in our consolidated liability for pension and postretirement benefits.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These amounts are subject to change, based on various factors.

	2010	2011	2012
		Millions	
Power:			
Hudson Environmental	$ 280	$ 5	$
Mercer Environmental	55	5	
Other Environmental	35	25	35
Exploration of New Nuclear Plant	10	15	30
Growth Opportunities	130	245	95
Other	240	255	320
Total Power	**$ 750**	**$ 550**	**$ 480**
PSE&G:			
Transmission			
Reliability Enhancements	$ 390	$ 635	$ 780
Facility Replacement	130	95	115
Support	5	10	5
Distribution			
Support Facilities	85	65	60
New Business	145	145	140
Reliability Enhancements	255	140	140
Facility Replacement	470	195	170
Environmental/Regulatory	75	45	45
Renewables / EMP	385	350	190
Total PSE&G	**$ 1,940**	**$ 1,680**	**$ 1,645**
Non-Utility Renewables	120	190	225
Other	30	20	40
Total PSEG	**$ 2,840**	**$ 2,440**	**$ 2,390**

Power

Power s projected expenditures for the various items listed above are primarily comprised of the following:

Hudson Environmental construction of pollution control equipment, including a selective catalytic reduction system, a scrubber and a baghouse at our Hudson facility.

Mercer Environmental construction of pollution control equipment, including scrubbers, at our Mercer facility.

Other Environmental construction of other pollution control equipment.

Exploration of New Nuclear Plant costs associated with exploring the feasibility of, and the technologies involved with, building a new nuclear plant.

Growth Opportunities costs associated with potential opportunities to build other new plants, such as peaking facilities, and various capital projects at existing facilities to either extend plants useful lives or increase operating output.

In 2009, Power made $669 million of capital expenditures (excluding $200 million for nuclear fuel), primarily related to the construction of pollution control equipment at its Hudson, Mercer and Keystone facilities.

PSE&G

PSE&G s projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G s projected expenditures for the various items reported above are primarily comprised of the following:

Support Facilities ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.

New Business investments made in support of new business (e.g. to add new customers).

Reliability Enhancements investments made to improve the reliability and efficiency of the system or function.

Facility Replacement investments made to replace systems or equipment in kind.

Environmental/Regulatory investments made in response to regulatory or legal mandates.

Renewables/EMP investments made in response to regulatory or legal mandates relating to renewable energy.

In 2009, PSE&G made $898 million of capital expenditures, including $855 million of investment in plant, primarily for transmission and distribution system reliability and $43 million in solar loan investments. This does not include $54 million spent on cost of removal.

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

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. See 12. Commitments and Contingent Liabilities for a discussion of contractual commitments related to the construction activity, discussed above, and for a variety of services for which annual amounts are not quantifiable. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. The table 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 Item 8. Financial Statements and Supplementary Data Note 13. Schedule of Consolidated Debt. The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data Note 19. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 year	2 - 3 years	4 - 5 years	Over 5 years
			Millions		
Contractual Cash Obligations					
Short-Term Debt Maturities					
PSEG	$ 530	$ 530	$	$	$
Long-Term Recourse Debt Maturities					
PSEG					
Power	3,126		1,466	459	1,201
PSE&G	3,577	300	300	975	2,002
Transition Funding (PSE&G)	1,276	186	400	439	251
Transition Funding II (PSE&G)	67	12	23	24	8
Energy Holdings	127		127		
Long-Term Non-Recourse Project Financing					
Energy Holdings	42	23	7	4	8
Interest on Recourse Debt					
PSEG					
Power	1,580	214	313	198	855
PSE&G	2,612	187	374	298	1,753
Transition Funding (PSE&G)	286	81	125	69	11
Transition Funding II (PSE&G)	9	3	4	2	
Energy Holdings	16	11	5		
Interest on Non-Recourse Project Financing					
Energy Holdings	7	3	2	1	1
Capital Lease Obligations					
PSEG	42	7	15	14	6
Power	9	1	3	4	1
Operating Leases					
PSE&G	16	5	7	3	1
Energy Holdings	1	1			
Energy-Related Purchase Commitments					
Power	3,250	873	1,131	692	554
Total Contractual Cash Obligations	**$ 16,043**	**$ 1,907**	**$ 4,302**	**$ 3,182**	**$ 6,652**
Commercial Commitments					
Standby Letters of Credit					
Power	$ 174	$ 174	$	$	$
Energy Holdings	3	3			
Guarantees and Equity Commitments					
Energy Holdings	61	28	33		
Total Commercial Commitments	**$ 238**	**$ 205**	**$ 33**	**$**	**$**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 21	$ 21	$	$	$
Power	(3)	(3)			
PSE&G	(30)	(30)			
Energy Holdings	132	132			

OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for further discussion.

Energy Holdings

We have 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 in the Consolidated Balance Sheets for such investments represent our equity investment, which is increased for our pro-rata share of earnings less any dividend distribution from such investments. The companies in which we invest that are accounted for under the equity method have an aggregate $94 million of long-term debt on their combined Consolidated Balance Sheets. Our pro-rata share of such debt is $47 million. This debt is non-recourse to us. We are 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.

Energy Holdings has investments in leveraged leases that are accounted for in accordance with GAAP 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 our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secure the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operation. For additional information, see Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Investments.

In the event that collectibility of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Energy Holdings 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 Energy Holdings 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.

CRITICAL ACCOUNTING ESTIMATES

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. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** 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.

Assumption	2009	2008	2007
Discount Rate	5.91%	6.80%	6.50%
Rate of Return on Plan Assets	8.75%	8.75%	8.75%

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Our 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, our measurement date. The discount rate used to determine year-end obligations is also used to develop the following year s net periodic pension cost.

Our 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 and long-term inflation assumptions.

Based on the above assumptions, we have estimated net periodic pension expense of approximately $130 million, net of amounts capitalized, and contributions of up to $415 million in 2010.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.50% rate of return and a 5.90% discount rate for 2011 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 our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

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

Assumption	**Change**	**As of 12/31/2009 Impact on Pension Benefit Obligation**	**Increase to Pension Expense in 2010**
		Millions	
Discount Rate	-1%	$ 515	$ 49
Rate of Return on Plan Assets	-1%	$	$ 31

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Accounting for Deferred Tax Assets

We provide for income taxes based on the liability method of accounting. 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.

***Assumptions and Approach Used*:** We evaluate the need for a valuation allowance against respective deferred tax assets based on such factors as:

- our expectation of future taxable income; and
- continued availability of certain tax planning strategies.

We do not believe a valuation allowance is necessary.

Effect if Different Assumptions Used**:** Our ability to realize the deferred tax assets are dependent on our ability to generate ordinary income and capital gains. Also, such factors as changes in tax laws, our ability to accurately forecast our financial condition and results of operations in future periods, as well as actual results of audits/examinations of ours and others filed tax returns by taxing authorities could result in the recording of a valuation allowance.

Uncertain Tax Positions

We are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate our obligations to taxing authorities.

Assumptions and Approach Used**:** We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that

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measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold.

We also have non-income tax obligations related to real estate, sales and use and employment-related taxes and ongoing appeals related to these tax matters. We record liabilities for such obligations when we believe they are both probable and reasonably estimable.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. We also assess our ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. We do not record valuation allowances for deferred tax assets related to capital losses that we believe will be realized in future periods.

***Effect if Different Assumptions Used*:** While we believe the resulting tax reserve balances as of December 31, 2009 are appropriately accounted for, the ultimate outcome of such matters could result in favorable or unfavorable adjustments to our consolidated financial statements and such adjustments could be material.

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments held as assets or liabilities on the balance sheet. This applies to all derivative instruments that we hold, except for those instruments for which we elect normal purchases normal sales treatment.

***Assumptions and Approach Used*:** 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, we 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, we developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of value to record in the financial statements.

We have entered into various derivative instruments to hedge exposure to commodity price risk and interest rate 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, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of derivative effectiveness. 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 instruments designated as cash flow hedges are recorded in earnings.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded on our Consolidated Statements or Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data Note 15. Financial Risk Management Activities.

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NDT Funds

Our NDT Funds are comprised of both debt and equity securities. 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 in our Statements of Operations as Other Income and Other Deductions. Unrealized losses that are deemed to be other-than-temporarily-impaired are charged against earnings rather than Accumulated Other Comprehensive Loss and reflected as a separate line in the Consolidated Statement of Operations.

Assumptions and Approach Used**:** The NDT fund investments are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. See Item 8. Financial Statements and Supplementary Data Note 15. Fair Value Measurements for additional information.

Effect if Different Assumptions Used**:** Any significant changes to the fair market values of the fund securities could result in a material change in the value of our NDT Fund, which could potentially result in additional funding requirements to satisfy our decommissioning obligations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Asset Retirement Obligations

Power, PSE&G and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These Asset Retirement Obligations (ARO) are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the ratemaking process. We accrete the ARO liability to reflect the passage of time.

Assumptions and Approach Used: Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement;
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities;
- discount rates;
- cost escalation rates;
- inflation rates; and
- if applicable, past experience with government regulators regarding similar obligations.

We review cost studies every three years unless new information necessitates updates more often. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power s nuclear facilities comprised 90% of Power s total AROs as of December 31, 2009. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

license renewals,

early shutdown

safe storage for a period of time after retirement

recovery from the Federal government of costs incurred for spent nuclear fuel

Effect if Different Assumptions Used: Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a 1% decrease in the discount rate used at December 31, 2009 would result in a $96 million increase in the Nuclear ARO. A 1% increase in the inflation rate used at December 31, 2009 would result in a $164 million increase in the Nuclear ARO. Also, if we did not assume that we would recover from the Federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $65 million at December 31, 2009. These changes would not have a material impact on net income in 2010.

Unbilled Revenues

Electric and gas revenues are recorded based on services rendered to customers during each accounting period. We record 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.

***Assumptions and Approach Used*:** 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. The resulting revenue and expense reflect the service rendered in the calendar month.

***Effect if Different Assumptions Used*:** Using benchmarks other than those used in this calculation could have a material effect on the amount of revenues accrued in a reporting period.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, 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 (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

Assumptions and Approach Used: PSE&G recognizes regulatory assets where it is probable that such costs will be recoverable in future rates from customers and regulatory liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the New Jersey Board of Public Utilities (BPU) either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G s regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a regulatory asset or liability:

past experience regarding similar items with the BPU;

treatment of a similar item in an order by the BPU for another utility;

passage of new legislation; and

recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. PSE&G s experience is that little of the deferred cost has been subsequently denied by the BPU. When the recovery of a regulated asset or payment of a regulatory liability is no longer probable, PSE&G charges or credits earnings, respectively.

Effect if Different Assumptions Used**:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our market-risk sensitive instruments and positions have the potential for losses arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of a number of our executive officers who ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related 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, we enter 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.

Value-at-Risk (VaR) Models

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

We manage our exposure at the portfolio level, which consists of owned generation, electric load-serving contracts, fuel supply contracts and energy derivatives designed to manage the risk around generation and load. We also monitor separately the risk of our trading activities and hedges. Non-trading mark-to-market (MTM) VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The non-trading MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities. The MTM derivatives that are not hedges are included in the trading VaR.

The VaR models used are variance/covariance models adjusted for the change of positions with a 95% confidence level and a one-day holding period for the trading and non-trading MTM activities, and a 95% confidence level with a one-week holding period for the portfolio VaR. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

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As of December 31, 2009 and 2008, Trading VaR was approximately $1 million.

For the Year Ended December 31, 2009	Trading VaR	Non-Trading MTM VaR
	Millions	
95% Confidence level, Loss could exceed VaR one day in 20 days:		
Period End	$ 1	$ 19
Average for the Period	$ 1	$ 34
High	$ 3	$ 49
Low	*	$ 19
99.5% Confidence level, Loss could exceed VaR one day in 200 days:		
Period End	$ 1	$ 30
Average for the Period	$ 1	$ 53
High	$ 5	$ 77
Low	*	$ 30

* less than $1 million

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. It is our policy to manage interest rate risk through the use of fixed and floating rate debt, interest rate swaps and interest rate lock agreements. We manage our interest rate exposures through a mix of fixed and floating rate debt.

As of December 31, 2009, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and

- a $213 million decrease in the fair value of debt, including a $77 million decrease at Power and a $125 million decrease at PSE&G.

Debt and Equity Securities

We have $2.9 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,

- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and

- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Funds are comprised of both fixed income and equity securities totaling $1.2 billion as of December 31, 2009. The fair value of equity securities is determined independently each month by the trustee. As of December 31, 2009, the portfolio was comprised of $650 million of equity securities and $549 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, 2009, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Funds by approximately $65 million.

We use 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

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component of the NDT Funds currently has a duration of 4.57 years and a yield of 3.68%. The portfolio s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2009, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $23 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data Note 15. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power s credit risk.

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.

Energy Holdings has credit risk with respect to its counterparties to power purchase agreements and other parties.

Energy Holdings also has credit risk related to its investments in leveraged leases, totaling $296 million, which is net of deferred taxes of $1.3 billion, as of December 31, 2009. These investments are largely concentrated in the energy industry. As of December 31, 2009, 39% of counterparties in the lease portfolio were rated investment grade by both S&P and Moody s. As of December 31, 2009, the weighted average credit rating of the lessees in Holdings leasing portfolio was BBB-/Baa3 by S&P and Moody s, respectively. 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, Energy Holdings 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 Energy Holdings 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 our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G 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, 2009 and 2008, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and 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 audits 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, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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 16 to the consolidated financial statements, the Company adopted new accounting guidance related to fair value measurements effective January 1, 2008.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2009, 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 24, 2010 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey

February 24, 2010

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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, 2009 and 2008, 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, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and 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 audits 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, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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 1 to the consolidated financial statements, PSEG Texas, LP was contributed to the Company in a transaction between entities under common control. The consolidated financial statements for all periods presented were retrospectively adjusted to reflect the operations of PSEG Texas, LP.

As discussed in Note 16 to the consolidated financial statements, the Company adopted new accounting guidance related to fair value measurements effective January 1, 2008.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey

February 24, 2010

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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, 2009 and 2008, 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, 2009. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and 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 audits 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 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, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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 16 to the consolidated financial statements, the Company adopted new accounting guidance related to fair value measurements effective January 1, 2008.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey

February 24, 2010

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31, 2009	2008	2007
OPERATING REVENUES	$ 12,406	$ 13,322	$ 12,677
OPERATING EXPENSES			
Energy Costs	5,711	7,295	6,512
Operation and Maintenance	2,603	2,486	2,406
Depreciation and Amortization	838	792	774
Taxes Other Than Income Taxes	133	136	139
Total Operating Expenses	9,285	10,709	9,831
OPERATING INCOME	3,121	2,613	2,846
Income from Equity Method Investments	39	37	115
Gain (Loss) on Disposal and (Impairment) on Equity Method Investments	(22)	(27)	137
Other Income	247	436	279
Other Deductions	(161)	(336)	(188)
Other-Than-Temporary Impairments	(61)	(220)	(73)
Interest Expense	(527)	(594)	(727)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,636	1,909	2,389
Income Tax Expense	(1,044)	(926)	(1,064)
INCOME FROM CONTINUING OPERATIONS	1,592	983	1,325
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax expense of $171 and $157 for the years ended 2008 and 2007, respectively		205	10
NET INCOME	$ 1,592	$ 1,188	$ 1,335
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,986	507,693	507,560
DILUTED	507,064	508,427	508,813
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$ 3.15	$ 1.94	$ 2.61
NET INCOME	$ 3.15	$ 2.34	$ 2.63
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$ 3.14	$ 1.93	$ 2.60
NET INCOME	$ 3.14	$ 2.34	$ 2.62
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 1.33	$ 1.29	$ 1.17

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 350	$ 321
Accounts Receivable, net of allowances of $79 and $66 in 2009 and 2008, respectively	1,229	1,398
Unbilled Revenues	411	454
Fuel	806	938
Materials and Supplies, net	361	317
Prepayments	161	150
Restricted Funds	2	118
Derivative Contracts	243	237
Other	83	66
Total Current Assets	3,646	3,999
PROPERTY, PLANT AND EQUIPMENT	22,069	20,818
Less: Accumulated Depreciation and Amortization	(6,629)	(6,385)
Net Property, Plant and Equipment	15,440	14,433
NONCURRENT ASSETS		
Regulatory Assets	5,769	6,352
Long-Term Investments	2,032	2,695
Nuclear Decommissioning Trust (NDT) Funds	1,199	970
Other Special Funds	149	133
Goodwill	16	16
Other Intangibles	123	53
Derivative Contracts	123	160
Other	233	238
Total Noncurrent Assets	9,644	10,617
TOTAL ASSETS	$ 28,730	$ 29,049

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2009	December 31, 2008
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 521	$ 1,033
Commercial Paper and Loans	530	19
Accounts Payable	1,081	1,227
Derivative Contracts	201	356
Accrued Interest	102	99
Accrued Taxes	90	8
Clean Energy Program	166	142
Obligation to Return Cash Collateral	95	102
Other	428	424
Total Current Liabilities	3,214	3,410
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	4,139	3,865
Regulatory Liabilities	404	355
Asset Retirement Obligations	439	576
Other Postretirement Benefit (OPEB) Costs	1,095	975
Accrued Pension Costs	1,094	1,196
Clean Energy Program	400	532
Environmental Costs	704	743
Derivative Contracts	40	164
Long-Term Accrued Taxes	538	1,241
Other	140	125
Total Noncurrent Liabilities	8,993	9,772
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,481	6,621
Securitization Debt	1,145	1,342
Project Level, Non-Recourse Debt	19	42
Total Long-Term Debt	7,645	8,005
SUBSIDIARY S PREFERRED STOCK WITHOUT MANDATORY REDEMPTION	80	80
STOCKHOLDERS EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2009 and 2008 533,556,660 shares	4,788	4,756
Treasury Stock, at cost, 2009 27,567,030 shares; 2008 27,538,762 shares	(588)	(581)
Retained Earnings	4,704	3,773
Accumulated Other Comprehensive Loss	(116)	(177)

Total Common Stockholders Equity	8,788	7,771
Noncontrolling Interest	10	11
Total Stockholders Equity	8,798	7,782
Total Capitalization	16,523	15,867
TOTAL LIABILITIES AND CAPITALIZATION	$ 28,730	$ 29,049

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	For the Years Ended December 31,		
	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,592	$ 1,188	$ 1,335
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations		(335)	(120)
Depreciation and Amortization	838	793	802
Amortization of Nuclear Fuel	121	101	95
Provision for Deferred Income Taxes (Other than Leases) and ITC	326	71	241
Non-Cash Employee Benefit Plan Costs	347	167	185
Lease Transaction Reserves, net of tax	(29)	490	0
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(678)	51	70
(Gain) Loss on Disposal and Impairment on Equity Method Investments	22	27	(137)
Gain on Sale of Investments	(167)	(11)	(20)
Undistributed Earnings from Affiliates	(28)	(40)	(10)
Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	25	(39)	22
Under Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	(32)	(43)	(71)
Over (Under) Recovery of Societal Benefits Charge (SBC)	4	(75)	(53)
Cost of Removal	(54)	(44)	(37)
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(50)	115	(48)
Net Change in Certain Current Assets and Liabilities	221	74	(198)
Employee Benefit Plan Funding and Related Payments	(446)	(139)	(96)
Other	(157)	(6)	(39)
Net Cash Provided By Operating Activities	1,855	2,345	1,921
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,794)	(1,771)	(1,348)
Settlement for Spent Nuclear Fuel Claim	47		
Proceeds from Sale of Discontinued Operations		925	600
Proceeds from Sale of Property, Plant and Equipment	2	9	55
Proceeds from the Sale of Capital Leases and Investments	880	77	703
Proceeds from NDT Funds Sales	1,769	3,060	1,672
Investment in NDT Funds	(1,798)	(3,093)	(1,703)
Restricted Funds	116	(11)	(41)
NDT Funds Interest and Dividends	39	48	48
Solar Loan Investments	(43)		
Other	(10)	(19)	23
Net Cash Provided By (Used In) Investing Activities	(792)	(775)	9
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	511	(46)	(317)
Issuance of Long-Term Debt	459	1,075	434
Issuance of Non-Recourse Debt			163
Issuance of Common Stock			83
Purchase of Common Treasury Stock		(92)	
Redemptions of Long-Term Debt	(820)	(1,582)	(551)
Repayment of Non-Recourse Debt	(286)	(56)	(57)
Redemption of Securitization Debt	(187)	(179)	(170)
Net Premium Paid on Early Extinguishment of Debt		(79)	
Premium Paid on Debt Exchange	(36)		
Cash Dividends Paid on Common Stock	(673)	(655)	(594)

Redemption of Debt Underlying Trust Securities			(660)
Other	(2)	(15)	19
Net Cash Used In Financing Activities	(1,034)	(1,629)	(1,650)
Net Increase (Decrease) in Cash and Cash Equivalents	29	(59)	280
Cash and Cash Equivalents at Beginning of Period	321	380	100
Cash and Cash Equivalents at End of Period	$ 350	$ 321	$ 380
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid	$ 1,364	$ 952	$ 678
Interest Paid, Net of Amounts Capitalized	$ 500	$ 557	$ 715

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Millions

	Common Stockholders Equity							
	Common Stock		Treasury Stock		Retained	Accumulated Other Comprehensive	Noncontrolling	
	Shs.	Amount	Shs.	Amount	Earnings	Loss	Interest	Total
Balance as of January 1, 2007	532	$ 4,661	(27)	$ (516)	$ 2,710	$ (108)	$ 6	$ 6,753
Net Income					1,335			1,335
Other Comprehensive Income (Loss), net of tax:								
Currency Translation Adjustment, net of tax						(3)		(3)
Available-for-Sale Securities, net of tax						(10)		(10)
Change in Fair Value of Derivative Instruments, net of tax						(290)		(290)
Reclassification Adjustments for Net Amounts included in Net Income, net of tax						144		144
Sale of Investments						1		1
Pension/OPEB adjustment, net of tax						50		50
Other Comprehensive Loss								(108)
Comprehensive Income								1,227
Adoption of Accounting Guidance for Leases, net of tax					(67)			(67)
Adoption of Accounting Guidance for Uncertain Tax Positions, net of tax					(123)			(123)
Cash Dividends on Common Stock					(594)			(594)
Issuance of Common Stock	2	35	2	48				83
Other		36		(10)				26
Balance as of December 31, 2007	534	$ 4,732	(25)	$ (478)	$ 3,261	$ (216)	$ 6	$ 7,305
Net Income					1,188			1,188
Other Comprehensive Income (Loss), net of tax:								
Currency Translation Adjustment, net of tax						(106)		(106)
Available-for-Sale Securities, net of tax						(79)		(79)
Change in Fair Value of Derivative Instruments, net of tax						253		253
Reclassification Adjustments for Net Amounts included in Net Income, net of tax						176		176
Pension/OPEB adjustment, net of tax						(205)		(205)
Other Comprehensive Income								39
Comprehensive Income								1,227
Adoption of Accounting Guidance for Fair Value Measurements, net of tax					(21)			(21)
Cash Dividends on Common Stock					(655)			(655)
Repurchase of Common Stock			(3)	(92)				(92)
Investment by Noncontrolling Interest							5	5
Other		24		(11)				13
Balance as of December 31, 2008	534	$ 4,756	(28)	$ (581)	$ 3,773	$ (177)	$ 11	$ 7,782

Net Income					1,592			1,592
Other Comprehensive Income (Loss), net of tax:								
Available-for-Sale Securities, net of tax						94		94
Change in Fair Value of Derivative Instruments, net of tax						356		356
Reclassification Adjustments for Net Amounts included in Net Income, net of tax						(348)		(348)
Pension/OPEB adjustment, net of tax						(29)		(29)
Other Comprehensive Income								73
Comprehensive Income								1,665
Adoption of Accounting Guidance for Non-Credit Losses, net of tax					12	(12)		
Cash Dividends on Common Stock					(673)			(673)
Noncontrolling Interest in Losses of Consolidated Entity							(1)	(1)
Other		32		(7)				25
Balance as of December 31, 2009	534	$ 4,788	(28)	$ (588)	$ 4,704	$ (116)	$ 10	$ 8,798

See Notes to Consolidated Financial Statements.

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PSEG POWER LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31, 2009	2008	2007
OPERATING REVENUES	$ 7,143	$ 8,483	$ 7,422
OPERATING EXPENSES			
Energy Costs	3,740	5,051	4,414
Operation and Maintenance	1,114	1,126	1,061
Depreciation and Amortization	203	181	158
Total Operating Expenses	5,057	6,358	5,633
OPERATING INCOME	2,086	2,125	1,789
Other Income	234	416	242
Other Deductions	(135)	(316)	(97)
Other-Than-Temporary Impairments	(60)	(219)	(73)
Interest Expense	(167)	(192)	(185)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,958	1,814	1,676
Income Tax Expense	(769)	(699)	(676)
INCOME FROM CONTINUING OPERATIONS	1,189	1,115	1,000
Loss from Discontinued Operations, net of tax benefit of $5 for the year ended 2007			(8)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 1,189	$ 1,115	$ 992

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 64	$ 40
Accounts Receivable	425	484
Accounts Receivable Affiliated Companies, net	459	730
Short-Term Loan to Affiliate		55
Fuel	806	938
Materials and Supplies, net	290	255
Derivative Contracts	231	248
Restricted Funds	2	117
Prepayments	64	55
Other	1	11
Total Current Assets	2,342	2,933
PROPERTY, PLANT AND EQUIPMENT	8,579	8,083
Less: Accumulated Depreciation and Amortization	(2,194)	(2,040)
Net Property, Plant and Equipment	6,385	6,043
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Funds	1,199	970
Goodwill	16	16
Other Intangibles	114	43
Other Special Funds	30	27
Derivative Contracts	118	160
Long-Term Accrued Taxes	39	
Other	90	74
Total Noncurrent Assets	1,606	1,290
TOTAL ASSETS	$ 10,333	$ 10,266
LIABILITIES AND MEMBER S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$	$ 530
Accounts Payable	622	759
Short-Term Loan from Affiliate	194	
Derivative Contracts	201	352
Accrued Interest	43	35
Other	163	179
Total Current Liabilities	1,223	1,855
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	644	368
Asset Retirement Obligations	226	334
Other Postretirement Benefit (OPEB) Costs	158	118
Derivative Contracts	26	111
Accrued Pension Costs	344	375

Environmental Costs	52	54
Long-Term Accrued Taxes		29
Other	72	47
Total Noncurrent Liabilities	1,522	1,436
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
LONG-TERM DEBT		
Total Long-Term Debt	3,121	2,653
MEMBER S EQUITY		
Contributed Capital	2,028	2,202
Basis Adjustment	(986)	(986)
Retained Earnings	3,486	3,225
Accumulated Other Comprehensive Loss	(61)	(119)
Total Member s Equity	4,467	4,322
TOTAL LIABILITIES AND MEMBER S EQUITY	$ 10,333	$ 10,266

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	For the Years Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,189	$ 1,115	$ 992
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	203	181	158
Amortization of Nuclear Fuel	121	101	95
Interest Accretion on Asset Retirement Obligations	27	25	23
Provision for Deferred Income Taxes and ITC	133	64	230
Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	25	(39)	22
Non-Cash Employee Benefit Plan Costs	76	23	28
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(50)	115	(48)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	97	(163)	38
Margin Deposit Asset	(43)	242	(79)
Margin Deposit Liability	12	77	(2)
Accounts Receivable	109	6	(107)
Accounts Payable	(115)	29	16
Accounts Receivable/Payable-Affiliated Companies, net	75	(17)	(64)
Other Current Assets and Liabilities	(27)	60	(18)
Employee Benefit Plan Funding and Related Payments	(114)	(20)	(15)
Other	(60)	7	(4)
Net Cash Provided By Operating Activities	1,658	1,806	1,265
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(869)	(978)	(715)
Settlement of Spent Nuclear Fuel Claim	47		
Proceeds from Sale of Discontinued Operations			325
Sales of Property, Plant and Equipment		2	40
Proceeds from NDT Funds Sales	1,769	3,060	1,672
NDT Funds Interest and Dividends	39	48	48
Investment in NDT Funds	(1,798)	(3,093)	(1,703)
Short-Term Loan Affiliated Company, net	55	(55)	
Restricted Funds	115	(10)	(40)
Other	(10)	(15)	(16)
Net Cash Used In Investing Activities	(652)	(1,041)	(389)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	209		84
Contributed Capital	230		
Cash Dividend Paid	(940)	(500)	(1,075)
Redemption of Long-Term Debt	(294)		
Redemption of Non-Recourse Long-Term Debt	(280)	(50)	(45)
Short-Term Loan Affiliated Company, net	194	(194)	160
Cash Payment for Debt Exchange	(101)		

Net Cash Used In Financing Activities	(982)	(744)	(876)
Net Increase in Cash and Cash Equivalents	24	21	
Cash and Cash Equivalents at Beginning of Period	40	19	19
Cash and Cash Equivalents at End of Period	$ 64	$ 40	$ 19
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid	$ 584	$ 552	$ 358
Interest Paid, Net of Amounts Capitalized	$ 160	$ 184	$ 196

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC

CONSOLIDATED STATEMENTS OF MEMBER S EQUITY

Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Member s Equity
Balance as of January 1, 2007	$ 2,202	$ (986)	$ 2,728	$ (177)	$ 3,767
Net Income			992		992
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax				(10)	(10)
Change in Fair Value of Derivative Instruments, net of tax				(292)	(292)
Reclassification Adjustments for Net Amount included in Net Income, net of tax				145	145
Pension/OPEB adjustment, net of tax				38	38
Other Comprehensive Loss					(119)
Comprehensive Income					873
Adoption of Accounting Guidance for Uncertain Tax Positions, net of tax			(14)		(14)
Cash Dividends Paid			(1,075)		(1,075)
Balance as of December 31, 2007	$ 2,202	$ (986)	$ 2,631	$ (296)	$ 3,551
Net Income			1,115		1,115
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax				(79)	(79)
Change in Fair Value of Derivative Instruments, net of tax				257	257
Reclassification Adjustments for Net Amount included in Net Income, net of tax				172	172
Pension/OPEB adjustment, net of tax				(173)	(173)
Other Comprehensive Income					177
Comprehensive Income					1,292
Adoption of Accounting Guidance for Fair Value Measurements, net of tax			(21)		(21)
Cash Dividends Paid			(500)		(500)
Balance as of December 31, 2008	$ 2,202	$ (986)	$ 3,225	$ (119)	$ 4,322
Net Income			1,189		1,189
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax				88	88
				358	358

Change in Fair Value of Derivative Instruments, net of tax					
Reclassification Adjustments for Net Amount included in Net Income, net of tax				(350)	(350)
Pension/OPEB adjustment, net of tax				(26)	(26)
Other Comprehensive Income					70
Comprehensive Income					1,259
Non-Cash Return of Capital Related to Debt Exchange	(404)				(404)
Adoption of Accounting Guidance for Non-Credit Losses, net of tax			12	(12)	
Contributed Capital	230				230
Cash Dividends Paid			(940)		(940)
Balance as of December 31, 2009	$ 2,028	$ (986)	$ 3,486	$ (61)	$ 4,467

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31,		
	2009	2008	2007
OPERATING REVENUES	$ 8,243	$ 9,038	$ 8,493
OPERATING EXPENSES			
Energy Costs	5,170	6,072	5,498
Operation and Maintenance	1,474	1,338	1,308
Depreciation and Amortization	608	583	591
Taxes Other Than Income Taxes	133	136	139
Total Operating Expenses	7,385	8,129	7,536
OPERATING INCOME	858	909	957
Other Income	8	12	16
Other Deductions	(3)	(4)	(4)
Interest Expense	(312)	(325)	(332)
INCOME BEFORE INCOME TAXES	551	592	637
Income Tax Expense	(226)	(228)	(257)
NET INCOME	325	364	380
Preferred Stock Dividends	(4)	(4)	(4)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 321	$ 360	$ 376

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 240	$ 91
Accounts Receivable, net of allowances of $78 in 2009 and $65 in 2008, respectively	800	909
Unbilled Revenues	411	454
Materials and Supplies	70	61
Prepayments	86	45
Deferred Income Taxes	52	52
Other	3	1
Total Current Assets	1,662	1,613
PROPERTY, PLANT AND EQUIPMENT	12,933	12,258
Less: Accumulated Depreciation and Amortization	(4,187)	(4,122)
Net Property, Plant and Equipment	8,746	8,136
NONCURRENT ASSETS		
Regulatory Assets	5,769	6,352
Long-Term Investments	204	158
Other Special Funds	51	46
Other	101	101
Total Noncurrent Assets	6,125	6,657
TOTAL ASSETS	$ 16,533	$ 16,406

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2009	December 31, 2008
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 498	$ 248
Commercial Paper and Loans		19
Accounts Payable	337	336
Accounts Payable Affiliated Companies, net	496	763
Accrued Interest	56	58
Accrued Taxes	4	3
Clean Energy Program	166	142
Derivative Contracts		14
Obligation to Return Cash Collateral	95	102
Other	210	227
Total Current Liabilities	1,862	1,912
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,710	2,533
Other Postretirement Benefit (OPEB) Costs	887	813
Accrued Pension Costs	565	634
Regulatory Liabilities	404	355
Clean Energy Program	400	532
Environmental Costs	652	689
Asset Retirement Obligations	211	240
Derivative Contracts		53
Long-Term Accrued Taxes	96	82
Other	29	31
Total Noncurrent Liabilities	5,954	5,962
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	3,271	3,463
Securitization Debt	1,145	1,342
Total Long-Term Debt	4,416	4,805
Preferred Stock Without Mandatory Redemption, $100 par value, 7,500,000 authorized; issued and outstanding, 2009 and 2008 795,234 shares	80	80
STOCKHOLDER S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2009 and 2008 132,450,344 shares	892	892
Contributed Capital	420	170

Basis Adjustment	986	986
Retained Earnings	1,918	1,597
Accumulated Other Comprehensive Income	5	2
Total Stockholder s Equity	4,221	3,647
Total Capitalization	8,717	8,532
TOTAL LIABILITIES AND CAPITALIZATION	$ 16,533	$ 16,406

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	For the Years Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 325	$ 364	$ 380
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	608	583	591
Provision for Deferred Income Taxes and ITC	194	86	(78)
Non-Cash Employee Benefit Plan Costs	236	129	140
Gain on Sale of Property, Plant and Equipment	(2)	(1)	(3)
Non-Cash Interest Expense	12	15	12
Cost of Removal	(54)	(44)	(37)
Employee Benefit Plan Funding and Related Payments	(288)	(108)	(69)
Over (Under) Recovery of Electric Energy Costs (BGS and NTC)	(70)	4	(28)
Over (Under) Recovery of Gas Costs	38	(47)	(43)
Over (Under) Recovery of SBC	4	(75)	(53)
Other Non-Cash Charges		(5)	(4)
Net Changes in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	152	(19)	(218)
Materials and Supplies	(9)	(8)	(3)
Prepayments	(41)	12	(48)
Accrued Taxes		(26)	2
Accounts Payable	1	11	71
Accounts Receivable/Payable-Affiliated Companies, net	(62)	(8)	54
Obligation to Return Cash Collateral	(7)	23	17
Other Current Assets and Liabilities	(37)	11	(15)
Other	(43)	16	10
Net Cash Provided By Operating Activities	957	913	678
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(855)	(761)	(570)
Solar Loan Investments	(43)		
Other	5		2
Net Cash Used In Investing Activities	(893)	(761)	(568)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	(19)	(46)	34
Issuance of Long-Term Debt	250	1,075	350
Redemption of Long-Term Debt	(203)	(901)	(113)
Redemption of Securitization Debt	(187)	(179)	(170)
Contributed Capital	250		
Deferred Issuance Costs	(2)	(6)	(3)
Premium Paid on Early Retirement of Debt		(32)	
Cash Dividends Paid on Common Stock			(200)
Preferred Stock Dividends	(4)	(4)	(4)

Net Cash Provided By (Used In) Financing Activities	85	(93)	(106)
Net Increase In Cash and Cash Equivalents	149	59	4
Cash and Cash Equivalents at Beginning of Period	91	32	28
Cash and Cash Equivalents at End of Period	$ 240	$ 91	$ 32
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid	$ 5	$ 125	$ 336
Interest Paid, Net of Amounts Capitalized	$ 299	$ 317	$ 314

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY

Millions

	Common Stock	Contributed Capital from PSEG	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2007	$ 892	$ 170	$ 986	$ 1,061	$ 1	$ 3,110
Net Income				380		380
Other Comprehensive Income, net of tax					1	1
Comprehensive Income						381
Cash Dividends on Common Stock				(200)		(200)
Cash Dividends on Preferred Stock				(4)		(4)
Balance as of December 31, 2007	$ 892	$ 170	$ 986	$ 1,237	$ 2	$ 3,287
Net Income				364		364
Comprehensive Income						364
Cash Dividends on Preferred Stock				(4)		(4)
Balance as of December 31, 2008	$ 892	$ 170	$ 986	$ 1,597	$ 2	$ 3,647
Net Income				325		325
Other Comprehensive Income, net of tax:					3	3
Comprehensive Income						328
Contributed Capital		250				250
Cash Dividends on Preferred Stock				(4)		(4)
Balance as of December 31, 2009	$ 892	$ 420	$ 986	$ 1,918	$ 5	$ 4,221

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated, (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid Atlantic United States and in other select markets. PSEG s four principal direct wholly owned subsidiaries are:

PSEG Power LLC (Power) which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply, energy trading and marketing and risk management functions through three principal direct wholly owned subsidiaries. Power s subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.

Public Service Electric and Gas Company (PSE&G) which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and FERC. Pursuant to applicable BPU orders, PSE&G is also investing in the development of solar generation projects and energy efficiency programs within its service territory.

PSEG Energy Holdings L.L.C. (Energy Holdings) which owns and operates primarily domestic projects engaged in the generation of energy and has invested in energy-related leveraged leases through its direct wholly owned subsidiaries. Certain Energy Holdings subsidiaries are subject to regulation by FERC and the states in which they operate. Energy Holdings is also investing in solar generation projects and exploring opportunities for other investments in renewable generation.

PSEG Services Corporation (Services) which provides management and administrative and general services to PSEG and its subsidiaries.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

On October 1, 2009, Energy Holdings distributed the outstanding equity of PSEG Texas, LP (PSEG Texas) to PSEG. PSEG in turn contributed it to Power as an additional equity investment. Power had been responsible for the operation of the Texas facilities under a management agreement since January 2008. This transaction was accounted for as a non-cash transfer of equity interest between entities under common control. Power recognized the Texas assets and liabilities at their carrying amounts (historical cost) at the date of transfer. In addition, as required under current guidance, Power accounted for the transaction to include the earnings and assets and liabilities related to PSEG Texas as if the transfer occurred at the beginning of the year, and prior years have been retrospectively adjusted to furnish comparative information.

For the year ended December 31, 2009, PSEG Texas had Operating Revenues of $371 million and a Net Loss of $4 million. As of December 31, 2009, PSEG Texas had total assets of $646 million, primarily related to Property, Plant and Equipment.

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 2. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 22. Related-Party Transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power and PSE&G also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. All revenues and expenses related to these facilities are consolidated at their respective pro-rata ownership share in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G s financial statements must reflect the economic effects of regulation. PSE&G is required to defer the recognition of costs (a regulatory asset) or record the recognition of 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 and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or competitive position, the associated regulatory asset or liability is charged or credited to income. Management believes that PSE&G s transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities.

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk from changes in interest rates, commodity prices, congestion costs and emission credit prices, pursuant to its business plans and prudent practices.

Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a fair value hedge, along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current-period earnings. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a cash flow hedge are recorded in Accumulated Other Comprehensive Income / Loss until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current-period earnings. For derivative contracts that do not qualify as hedges or are not designated as normal purchases or sales or as cash flow hedges, changes in fair value are recorded in current-period earnings.

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

For additional information regarding derivative financial instruments, see Note 15. Financial Risk Management Activities.

Revenue Recognition

The majority of Power s revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power s revenue also includes changes in the value of non trading energy derivative contracts that are not designated as normal purchases or sales or as hedges of other positions. Power records margins from energy trading on a net basis. See Note 15. Financial Risk Management Activities for further discussion.

PSE&G s revenues are recorded based on services rendered to customers. 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. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated 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.

Energy Holdings revenues are earned from income relating to its investments in leveraged leases, which is recognized by a method which produces a constant after-tax 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

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losses incurred as a result of a lease termination are recorded as Operating Revenue as these events occur in the ordinary course of business of managing the investment portfolio. See Note 7. Long-Term Investments for further discussion.

Depreciation and Amortization

Power calculates depreciation on generation-related assets under the straight-line method based on the assets estimated useful lives. The estimated useful lives are:

general plant assets three years to 25 years

fossil production assets ten years to 79 years

nuclear generation assets 53 years to 58 years

pumped storage facilities 76 years

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was 2.44% for 2009, 2.47% for 2008 and 2.46% for 2007.

Taxes Other Than Income Taxes

Excise taxes, transitional energy facilities assessment (TEFA) and gross receipts tax (GRT) collected from PSE&G s customers are presented in the financial statements on a gross basis. For the years ended December 31, 2009, 2008 and 2007, combined TEFA and GRT of $146 million, $150 million and $154 million, respectively, are reflected in Operating Revenues and $133 million, $136 million and $140 million, respectively, are included in Taxes Other Than Income Taxes on the Consolidated Statements of Operations.

Interest Capitalized During Construction (IDC) and Allowance for Funds Used During Construction (AFUDC)

IDC represents the cost of debt used to finance construction at Power. AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. The amount of IDC or AFUDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate IDC or AFUDC for the years ended December 31, 2009, 2008 and 2007 are as follows:

	IDC/AFUDC Capitalized					
	2009		2008		2007	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
Power	$ 58	6.78%	$ 44	6.63%	$ 33	6.81%
PSE&G	$ 1	0.88%	$ 4	3.46%	$ 3	5.44%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG s subsidiaries based on the taxable income or loss of each subsidiary. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 19. Income Taxes for further discussion.

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Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Materials and Supplies and Fuel

Materials and supplies for Power and Energy Holdings are valued at the lower of average cost or market. Fuel inventory at Power is carried at cost and evaluated for recoverability based on its expected use in Power s generation facilities. PSE&G s materials and supplies are carried at average cost consistent with the rate-making process.

Restricted Funds

Power s restricted funds represent restricted cash for qualifying expenditures for solid waste disposal technology related to pollution control notes issued by Power for two of its coal-fired generation stations.

PSE&G s restricted funds represent revenues collected from its retail electric customers that must be used to pay the principal, interest and other expenses associated with the securitization bonds of Transition Funding and Transition Funding II.

Property, Plant and Equipment

Power capitalizes costs which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

PSE&G s additions to and replacements of existing property, plant and equipment are capitalized at original cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Other Special Funds

Other Special Funds represents amounts deposited to fund a Rabbi Trust which was established to meet the obligations related to two non-qualified pension plans and a deferred compensation plan. See Note 8. Available-for-Sale Securities for further discussion.

Nuclear Decommissioning Trust (NDT) Funds

Realized gains and losses on securities in the NDT Funds are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit loss on debt securities which is recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 8. Available-for-Sale Securities for further discussion.

Investments in Corporate Joint Ventures and Partnerships

Generally, PSEG s interests in active joint ventures and partnerships are accounted for under the equity method of accounting when its respective ownership interests are 50% or less, it is not the primary beneficiary or the entity is not a VIE, and significant influence over joint venture or partnership operating and management decisions exists. For investments in which significant influence does not exist and PSEG is not the primary beneficiary, the cost method of accounting is applied.

Pension and Other Postretirement Benefits (OPEB) Plan Assets

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent

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pricing services based upon the type of asset class as reported by the fund managers at the measurement dates (December 31) for all plan assets. See Note 11. Pension, OPEB and Savings Plans for further discussion.

Basis Adjustment

Power and PSE&G have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on Power s and PSE&G s Consolidated Balance Sheets. The $986 million is a reduction of Power s Member s Equity and an addition to PSE&G s Common Stockholder s Equity. These amounts are eliminated on PSEG s consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

Reclassifications

Certain reclassifications were made to the prior period financial statements in accordance with new accounting guidance adopted in 2009. Minority interests of $11 million were reclassified from Other Noncurrent Liabilities to Noncontrolling Interests in PSEG s Consolidated Balance Sheet as of December 31, 2008.

In addition, other-than-temporary impairments related to Power s credit losses on available-for-sale debt securities in its NDT Funds were reclassified from Other Deductions to a separate line caption in the Consolidated Statements of Operations of PSEG and Power, for the years ended December 31, 2008 and 2007, respectively.

As discussed previously, as a result of the transfer of the assets during 2009, the prior period financial statements for Power have also been retrospectively adjusted to include the earnings and assets and liabilities related to PSEG Texas. This resulted in an increase to Power s Operating Revenues of $713 million and $626 million for the years ended December 31, 2008 and 2007, respectively, with an increase to Power s Net Income of $65 million and $51 million for those years. The adjustments also resulted in an increase of $807 million to Power s Total Assets as of December 31, 2008, primarily related to Property, Plant and Equipment at the Texas facilities.

Note 2. Variable Interest Entities

PSE&G has determined that Transition Funding and Transition Funding II are variable interest entities (VIEs) for which it is the primary beneficiary. Accordingly, PSE&G consolidates the VIEs assets and liabilities within its Consolidated Balances, of which the most significant amounts are listed in the table below:

	As of December 31,	
	2009	**2008**
	Millions	

Regulatory Assets	$ 1,367	$ 1,546
Long-Term Debt, including Current Portion	$ 1,343	$ 1,530
Maximum Exposure to Loss*	$ 16	$ 15

* PSE&G s maximum exposure to loss is equal to its equity investment in these VIEs. The risk of actual loss to PSE&G is considered remote.

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Transition Funding and Transition Funding II were formed solely for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to the trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

Energy Holdings has variable interests through its investments in two projects for renewable energy where it is also the primary beneficiary. As a result, Energy Holdings consolidates the assets and liabilities of these projects in the amounts disclosed below:

	As of December 31, 2009	2008
	Millions	
Property, Plant and Equipment	$ 13	$ 9
Other Assets	$ 17	$ 1
Notes Payable	$ 4	$ 2
Other Liabilities	$ 7	$
Maximum Exposure to Loss*	$ 21	$ 6

* Energy Holdings maximum exposure to loss is equal to its equity investment in these VIEs. The risk of actual loss to Energy Holdings is considered remote.

Energy Holdings is also committed to fund any operating losses on one of the partnerships up to $11 million through 2011.

Note 3. Recent Accounting Standards

New Standards Adopted during 2009

During 2009, we have adopted several new accounting standards. The new standards adopted did not have a material impact on our financial statements. The following is a summary of the requirements and impacts of the new standards.

Noncontrolling Interests in Consolidated Financial Statements

changes the financial reporting relationship between a parent and noncontrolling interests,

requires all entities to report noncontrolling interests in subsidiaries as a separate component of equity in the consolidated financial statements,

requires net income attributable to the noncontrolling interests to be shown on the face of the income statement in addition to net income attributable to the controlling interest, and applies prospectively, except for presentation and disclosure requirements, which are applied retrospectively. We revised the balance sheet presentations as required by the standard. The income statement impact was immaterial.

Disclosures about Derivative Instruments and Hedging Activities

requires an entity to disclose an understanding of

- how and why it uses derivatives,
- how derivatives and related hedged items are accounted for, and
- the overall impact of derivatives on an entity s financial statements.

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The required disclosures are included in Note 15. Financial Risk Management Activities.

Subsequent Events

establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued, and

requires the disclosure of the date through which subsequent events have been evaluated and whether that date is the date on which the financial statements were issued or the date on which the financial statements were available to be issued.

We evaluated subsequent events through February 24, 2010, which is the date the financial statements were issued.

Recognition and Presentation of Other-Than-Temporary Impairments

revises recognition guidance in determining whether a debt security is other-than-temporarily impaired. A debt security is considered other-than-temporarily impaired in either of the following circumstances if the fair value is less than the amortized cost:

- an entity has an intent to sell the security, or it is more-likely-than-not that an entity will be required to sell the security prior to the recovery of its amortized cost basis, or
- an entity does not expect to recover the entire amortized cost basis of the security.

provides further guidance to determine the amount of impairment to be recorded in earnings (credit-related loss) and/or Accumulated Other Comprehensive Income (Loss) (non-credit related loss).

We recorded a cumulative-effect adjustment to reclassify $12 million of non-credit losses, net-of-tax, from Retained Earnings to Accumulated Other Comprehensive Income (Loss) on April 1, 2009 at the initial adoption date. The expanded disclosures required by the standard are included in Note 8. Available-for-Sale Securities.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly

provides guidance:

- to determine if there has been a significant decrease in the volume and level of activity for the asset or liability, and
- to estimate fair values, when transactions or quoted prices are not determinative of fair value**.**

See Note 16. Fair Value Measurements for further information.

Investments in Certain Entities That Calculate Net Asset Value Per Share

provides guidance on measuring fair value of certain alternative investments, and

permits the use of an investment s net asset value to estimate its fair value, as a practical expedient, under certain circumstances.

A portion of pension and OPEB plan assets is invested in private equity and real estate funds and is measured using net asset value. See Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans for further information.

Employers Disclosures about Postretirement Benefit Plan Assets

This accounting standard requires additional disclosures about the fair value of plan assets of a defined benefit pension or other postretirement plan, including

how investment allocation decisions are made by management,

major categories of plan assets,

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- significant concentrations of risk within plan assets, and

- inputs and valuation techniques used to measure the fair value of plan assets and effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period.

See Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans for required disclosures.

The FASB Accounting Standards Codification and the Hierarchy of GAAP

- issued as the single source of authoritative non-governmental GAAP other than the SEC rules and regulations, and

- does not change current GAAP, but is intended to simplify user access by providing all the authoritative GAAP literature related to a particular topic in one place.

We eliminated specific accounting references in our SEC filings and other documents and replaced them with more general topical references included in the Codification.

New Accounting Standards Issued But Not Adopted as of December 31, 2009

Consolidation of VIEs

This accounting standard has been issued to amend the requirements for consolidation of VIEs which:

- removes the exception of applying consolidation guidance to qualifying special-purpose entities,

- amends the criteria in determination of a primary beneficiary, such that a primary beneficiary would be an enterprise with the power to direct the activities of a VIE that most significantly impact the economic performance of a VIE and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE, and

- requires ongoing assessment of our involvement in the activities of the VIEs.

We adopted this standard effective January 1, 2010. We do not anticipate a material impact related to the adoption of this standard. However, due to evolving interpretations of this guidance, we have not completed our assessment.

Note 4. Discontinued Operations, Dispositions and Impairments

Discontinued Operations

Power

In May 2007, Power completed the sale of Lawrenceburg Energy Center (Lawrenceburg), a 1,096-megawatt (MW), gas-fired combined cycle electric generating plant located in Lawrenceburg, Indiana, to AEP Generating Company. The sale price was $325 million. Lawrenceburg s operating results for the year ended December 31, 2007, which were reclassified to Discontinued Operations, are summarized below:

		Year Ended December 31, 2007
		Millions
Operating Revenues	$	
Loss Before Income Taxes	$	(13)
Net Loss	$	(8)

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Energy Holdings

Bioenergie

In November 2008, Energy Holdings sold its 85% ownership interest in Bioenergie for $40 million. Bioenergie owns three biomass generation plants in Italy. The sale resulted in an after-tax loss of $15 million recorded in 2008 in Discontinued Operations. Net cash proceeds, after realization of tax benefits, were approximately $70 million.

Bioenergie s operating results for the years ended December 31, 2008 and 2007, which were reclassified to Discontinued Operations, are summarized below:

	Years Ended December 31, 2008	2007
	Millions	
Operating Revenues	$ 40	$ 22
Income (Loss) Before Income Taxes	$ 5	$ (10)
Net Income (Loss)	$ 3	$ (6)

SAESA Group

In July 2008, Energy Holdings sold its investment in the SAESA Group, which consists of certain transmission, distribution and generation companies in Chile, for a total purchase price of $1.3 billion, including the assumption of $413 million of the consolidated debt of the group. The sale resulted in an after-tax gain of $187 million, which is included in Discontinued Operations. Net cash proceeds, after Chilean and U.S. taxes of $269 million, were $612 million.

SAESA Group s operating results for the years ended December 31, 2008 and 2007, which were reclassified to Discontinued Operations, are summarized below:

	Years Ended December 31, 2008	2007
	Millions	
Operating Revenues	$ 379	$ 442
Income Before Income Taxes	$ 36	$ 55
Net Income (Loss)	$ 30	$ (34)

Electroandes S.A. (Electroandes)

In October 2007, Energy Holdings sold its investment in Electroandes, a hydro-electric generation and transmission company in Peru, for a total purchase price of $390 million, including the assumption of approximately $108 million of debt. Net proceeds, after tax of $72 million and including dividends received prior to closing, were $220 million. Energy Holdings recorded an after-tax gain of $48 million recorded in the fourth quarter of 2007 which is included in Discontinued Operations.

Energy Holdings recorded a $19 million income tax expense in the second quarter of 2007, as the income generated by Electroandes was no longer expected to be indefinitely reinvested.

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Electroandes operating results for the year ended December 31, 2007, which were reclassified to Discontinued Operations, are summarized below:

	Year Ended December 31, 2007
	Millions
Operating Revenues	$ 41
Income Before Income Taxes	$ 15
Net Income	$ 10

Dispositions and Impairments

Energy Holdings

Leveraged Leases

For the year ended December 31, 2009, Energy Holdings sold its interest in 14 leveraged leases with a total book value of approximately $672 million, including 12 international leases for which the IRS has disallowed deductions taken in prior years. Total proceeds for the sales were approximately $830 million and resulted in an after-tax gain of $70 million. Energy Holdings sold its interest in two additional leases in January 2010, including one of the international leases discussed above, for approximately $106 million, resulting in an after-tax gain of $8 million. Proceeds from these transactions are being used to reduce the tax exposure related to these lease investments. For additional information see Note 12. Commitments and Contingent Liabilities.

GWF Energy LLC (GWF Energy)

In May 2009, Energy Holdings entered into a Memorandum of Understanding under which it intends to sell, in two separate transactions, its 60% ownership interest in GWF Energy, an equity method investment, for a total purchase price of $70 million. As a result, Energy Holdings recorded an after-tax impairment charge of $3 million.

Energy Holdings completed the first stage of the sale in June 2009, selling a 10.1% interest in GWF Energy for approximately $7 million. The sale of Energy Holdings remaining 49.9% interest is subject to certain conditions, including regulatory approval of a power purchase agreement and FERC s approval of the sale.

PPN Power Generating Company Limited (PPN)

In May 2009, Energy Holdings sold its 20% ownership interest in PPN, which owns and operates a 330 MW generation facility in India for approximately book value. Energy Holdings had previously recorded after-tax impairment losses of $9 million and $2 million for the years ended December 31, 2008 and 2007 related to its investment in India based on its estimated market valuation of the project.

Midland Cogeneration Venture LP (MCV)

In May 2009, Energy Holdings sold its 6.5% interest in MCV for an after-tax gain of $2 million.

Chilquinta Energia S.A. (Chilquinta) and Luz del Sur S.A.A. (LDS)

In 2007, Energy Holdings closed on the sales of its 50% ownership interest in the Chilean electric distributor, Chilquinta and its affiliates and its 38% ownership interest in the Peruvian electric distributor, LDS and its affiliates, for $685 million. Net cash proceeds after taxes were approximately $480 million, which resulted in an after-tax loss of $23 million.

Other

Based on its periodic review of the operation and the political and economic circumstances in Venezuela, Energy Holdings recorded after-tax impairment charges to its investments in Venezuela of $3 million, $4 million and $7 million for years ended December 31, 2009, 2008 and 2007, respectively.

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As of December 31, 2009 and December 31, 2008, Energy Holdings remaining international investments totaled $3 million and $24 million, respectively, after the impairments.

Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2009 and 2008 is detailed below:

	Power	PSE&G	Other	PSEG Consolidated
			Millions	
December 31, 2009				
Generation:				
Fossil Production	$ 5,910	$	$	$ 5,910
Nuclear Production	833			833
Nuclear Fuel in Service	631			631
Other Production-Solar		13	13	26
Construction Work in Progress	1,124			1,124
Total Generation	8,498	13	13	8,524
Transmission and Distribution:				
Electric Transmission		1,891		1,891
Electric Distribution		5,804		5,804
Gas Transmission		95		95
Gas Distribution		4,422		4,422
Construction Work in Progress		108		108
Plant Held for Future Use		7		7
Other		421		421
Total Transmission and Distribution		12,748		12,748
Other	81	172	544	797
Total	**$ 8,579**	**$ 12,933**	**$ 557**	**$ 22,069**

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	Power	PSE&G	Other	PSEG Consolidated
		Millions		
December 31, 2008				
Generation:				
Fossil Production	$ 5,701	$	$	$ 5,701
Nuclear Production	988			988
Nuclear Fuel in Service	549			549
Construction Work in Progress	776			776
Total Generation	8,014			8,014
Transmission and Distribution:				
Electric Transmission		1,655		1,655
Electric Distribution		5,567		5,567
Gas Transmission		88		88
Gas Distribution		4,228		4,228
Construction Work in Progress		176		176
Plant Held for Future Use		9		9
Other		471		471
Total Transmission and Distribution		12,194		12,194
Other	69	64	477	610
Total	**$ 8,083**	**$ 12,258**	**$ 477**	**$ 20,818**

Power and PSE&G have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of Power s and PSE&G s jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

December 31, 2009	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	22.50%	$ 242	$ 117
Keystone	22.84%	$ 373	$ 96
Nuclear Generating			
Peach Bottom	50.00%	$ 300	$ 135
Salem	57.41%	$ 720	$ 183
Nuclear Support Facilities	Various	$ 105	$ 18
Pumped Storage Facilities			
Yards Creek	50.00%	$ 31	$ 22

Merrill Creek Reservoir	13.91%	$ 1	$
PSE&G:			
Transmission Facilities	Various	$ 146	$ 60
Linden SNG Plant	90.00%	$ 5	$ 5

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December 31, 2008	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	22.50%	$ 228	$ 113
Keystone	22.84%	$ 306	$ 90
Nuclear Generating			
Peach Bottom	50.00%	$ 261	$ 128
Salem	57.41%	$ 732	$ 202
Nuclear Support Facilities	Various	$ 132	$ 24
Pumped Storage Facilities			
Yards Creek	50.00%	$ 29	$ 22
Merrill Creek Reservoir	13.91%	$ 1	$
PSE&G:			
Transmission Facilities	Various	$ 142	$ 58
Linden SNG Plant	90.00%	$ 5	$ 5

Power holds undivided ownership interests in the jointly-owned facilities above, excluding related nuclear fuel and inventories. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power s share of expenses for the jointly-owned facilities is included in the appropriate expense category. All owners receive revenue allocations based on their ownership percentages. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners reviews/approves major planning, financing and budgetary (capital and operating) decisions.

RRI Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by all co-owners makes all planning, financing and budgetary (capital and operating) decisions.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. First Energy Corporation is also a co-owner and the operator of this facility. First Energy submits separate capital and Operations and Maintenance budgets, subject to the approval of Power.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Reservoir is the owner-operator of this facility. The operator submits separate capital and Operations and Maintenance budgets, subject to the approval of the non-operating owners.

Note 6. Regulatory Assets and Liabilities

As discussed in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, PSE&G prepares its financial statements in accordance with GAAP accounting for regulated utilities. A regulated utility is required to defer the recognition of costs (a regulatory asset) or the recognition of 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. These costs are deferred based on rate orders issued by the BPU or FERC or PSE&G s experience with prior rate cases. With the exception of the Customer Care System

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regulatory asset, which is expected to be decided in its currently pending rate case, all of PSE&G s regulatory assets and liabilities at December 31, 2009 and 2008 are supported by written rate orders, either explicitly or implicitly through the BPU s treatment of various cost items.

Regulatory assets are subject to prudence reviews and can be disallowed in the future by regulatory authorities. PSE&G believes that all of its regulatory assets are probable of recovery. To the extent that collection of any regulatory assets or payments of regulatory liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following regulatory assets and liabilities:

	As of December 31,		
	2009	2008	Recovery/Refund Period
	Millions		
Regulatory Assets			
Stranded Costs To Be Recovered	$ 2,176	$ 2,479	Through December 2015(1)(2)
Manufactured Gas Plant (MGP) Remediation Costs	694	709	Various(2)
Pension and Other Postretirement	1,053	988	Various
Deferred Income Taxes	409	421	Various
Societal Benefits Charges (SBC)	188	209	Various(2)
New Jersey Clean Energy Program	566	674	To be determined(2)
Gas Contract Mark-to-Market	112	384	Various(1)
OPEB Costs	58	77	Through December 2012(2)
Unamortized Loss on Reacquired Debt and Debt Expense	106	112	Over remaining debt life(1)
Conditional Asset Retirement Obligation	64	92	Various
Repair Allowance Taxes	37	45	Through August 2013(1)(2)
Uncertain Tax Positions	55	39	Various
Regulatory Restructuring Costs	18	23	Through August 2013(1)(2)
Gas Margin Adjustment Clause	45	34	To be determined(2)
Customer Care System	38	14	To be determined
Plant and Regulatory Study Costs	11	13	Through December 2021(2)
Incurred But Not Reported Claim Reserve	16	12	Various
Asbestos Abatement	8	8	Through 2020(2)
Non-Utility Generation Charge (NGC)	86		To be determined
Other	29	19	Various
Total Regulatory Assets	**$ 5,769**	**$ 6,352**	

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	As of December 31, 2009	As of December 31, 2008	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Cost of Removal	$ 265	$ 269	Various
Overrecovered Gas Costs	45	7	Through September 2010(1)(2)
Excess Cost of Removal	24	38	Through November 2011(1)(2)
Overrecovered Electric Costs	41	14	To be determined(1)(2)
NGC		9	To be determined(2)
Renewables & Energy Efficiency	9		Various(1)(2)
Other	20	18	Various(1)
Total Regulatory Liabilities	**$ 404**	**$ 355**	

(1) Recovered/Refunded with interest

(2) Recoverable/Refundable per specific rate order

All regulatory assets and liabilities are excluded from PSE&G s rate base unless otherwise noted. The regulatory assets and liabilities in the table above are defined as follows:

Stranded Costs To Be Recovered: This reflects deferred costs, which are being recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and being collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Funds collected are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes.

Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G s transition costs related to deregulation, as approved by the BPU.

Manufactured Gas Plant (MGP) Remediation Costs: Represents the low end of the range for the remaining environmental investigation and remediation program costs that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the Remediation Adjustment Charge (RAC) clause in the Societal Benefits Charges (SBC).

Pension and Other Postretirement: Pursuant to the adoption of accounting guidance for employers defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs will be amortized and recovered in future rates.

Deferred Income Taxes: This amount represents the portion of deferred income taxes that will be recovered through future rates, based upon established regulatory practices, which permit the recovery of current taxes. Accordingly, this Regulatory Asset is offset by a deferred tax liability and is expected to be recovered, without interest, over the period the underlying book-tax timing differences reverse and become current taxes.

SBC: The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act (Competition Act), includes costs related to PSE&G s electric and gas business as follows: 1) the Universal Service Fund; 2) Energy Efficiency and Renewable Energy Programs; 3)

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Social Programs (electric only) which include electric bad debt expense; and 4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.

New Jersey Clean Energy Program: The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs for the period 2009-2012.

Gas Contract Mark-to-Market (MTM): The fair value of gas hedge contracts and gas cogeneration supply contracts. This asset is offset by a derivative liability and an intercompany payable in the Consolidated Balance Sheets.

OPEB Costs: Include costs associated with the adoption of accounting guidance for employers benefits other than pensions, which were deferred for OPEB costs incurred by rate-regulated enterprises.

Unamortized Loss on Reacquired Debt and Debt Expense: Represents losses on reacquired long-term debt, which are recovered through rates over the remaining life of the debt.

Conditional Asset Retirement Obligation: These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.

Repair Allowance Taxes: This represents tax, interest and carrying charges relating to disallowed tax deductions for repair allowance as authorized by the BPU with recovery over 10 years effective August 1, 2003.

Uncertain Tax Positions: The amount recorded for uncertain tax positions which will be recoverable in future rates.

Regulatory Restructuring Costs: These are costs related to the restructuring of the energy industry in New Jersey through the Competition Act and include such items as the system design work necessary to transition PSE&G to a transmission and distribution only company, as well as costs incurred to transfer and establish the generation function as a separate corporate entity with recovery over 10 years beginning August 1, 2003.

Gas Margin Adjustment Clause: PSE&G defers the margin differential received from Transportation Gas Service Non-Firm Customers versus bill credits provided to Basic Gas Supply Service (BGSS)-Firm customers.

Customer Care System: These are deferred costs associated with the replacement of the PSE&G s legacy customer accounting system which was placed in service in March 2009. Recovery has been requested in the currently pending base rate case.

Plant and Regulatory Study Costs: These are costs incurred by PSE&G and required by the BPU which are related to current and future operations, including safety, planning, management and construction.

Incurred But Not Reported Claim Reserve: Represents reserves for worker s compensation and injuries and damages that exceed the amounts recognized in rates on a settlement accounting basis.

Asbestos Abatement: Represents costs incurred to remove and dispose of asbestos insulation at PSE&G s then-owned fossil generating stations. Per a December 1992 BPU order, these costs are treated as Cost of Removal for ratemaking purposes.

NGC: Represents the difference between the cost of non-utility generation and the amounts realized from selling that energy at market rates through PJM. The BPU instructed PSE&G to transfer the remaining $150 million debit balance for the Market Transition Charge (MTC) from the SBC to the NGC in March 2007.

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Other Regulatory Assets: This includes the following: 1) BGS auction costs; 2) Undercollected gas cost of removal; 3) an offset to a liability for future demand side management standard offer spending; and 4) costs related to the Carbon Abatement and Solar Loan I programs.

Electric Cost of Removal: PSE&G accrues and collects for cost of removal in rates. The liability for non-legally required cost of removal is classified as a Regulatory Liability. This liability is reduced as removal costs are incurred. Accumulated cost of removal is a reduction to the rate base.

Overrecovered Gas Costs: These costs represent the overrecovered amounts associated with BGSS, as approved by the BPU.

Excess Cost of Removal: The BPU directed PSE&G to refund $66 million of excess gas cost of removal accruals over a five-year period ending November 2011.

Overrecovered Electric Energy Costs: These costs represent the overrecovered amounts associated with Basic Generation Service (BGS), as approved by the BPU.

Renewables & Energy Efficiency: These costs are the overrecovered amounts associated with various renewable energy and energy efficiency programs.

Other Regulatory Liabilities: This includes the following: 1) a retail adder included in the BGS charges; 2) amounts collected from customers in order for Transition Funding to obtain a AAA rating on its transition bonds; 3) third party billing discounts related to the Competition Act; 4) the costs associated with the acceleration of capital infrastructure investments under the Capital Economic Stimulus Program; and 5) an overrecovery of Transmission Formula Rates.

Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2009 and 2008 included the following:

	As of December 31,	
	2009	2008
Power	Millions	
Partnerships and Corporate Joint Ventures	$ 36	$ 23
Other Investments		12
PSE&G		
Life Insurance and Supplemental Benefits	$ 156	$ 151
Other Investments	48	7
Energy Holdings		
Leveraged Leases	$ 1,609	$ 2,279
Partnerships and Corporate Joint Ventures	183	202
Other Investments		21

Total Long-Term Investments	**$ 2,032**	**$ 2,695**

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Leveraged Leases

The net investment in leveraged leases was comprised of the following:

	As of December 31, 2009	2008
	Millions	
Lease rents receivable (net of non-recourse debt)	$ 1,587	$ 2,749
Estimated residual value of leased assets	934	971
	2,521	3,720
Unearned and deferred income	(912)	(1,441)
Total investments in leveraged leases	1,609	2,279
Deferred tax liabilities	(1,313)	(1,994)
Net investment in leveraged leases	**$ 296**	**$ 285**

The pre-tax income and income tax effects related to investments in leveraged leases were as follows:

	Years Ended December 31, 2009	2008	2007
		Millions	
Pre-tax income (loss) of leveraged leases	$ 23	$ (408)	$ 114
Income tax expense (benefit) on pre-tax income of leveraged leases	$ 23	$ (98)	$ 36
Amortization of investment tax credits of leveraged leases	$	$	$ (1)

Investments in and Advances to Affiliates

Investments in net assets of affiliated companies accounted for under the equity method of accounting by Energy Holdings amounted to $176 million and $180 million as of December 31, 2009 and 2008, respectively. The decrease of $4 million between the December 31, 2009 and 2008 equity investment balances was due primarily to additional undistributed earnings from the investments in 2009 being more than offset by the further impairment of our equity investment in Turboven and the partial sale of the equity investment in GWF Energy in 2009 (see Note 4. Discontinued Operations, Dispositions and Impairments). During the three years ended December 31, 2009, 2008 and 2007, the amount of dividends from these investments was $10 million, $25 million and $108 million, respectively. Energy Holdings share of income and cash flow distribution percentages ranged from 40% to 50% as of December 31, 2009.

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Power and Energy Holdings had the following equity method investments as of December 31, 2009:

Name	Location	% Owned
Power		
Keystone	PA	23%
Conemaugh	PA	23%
Energy Holdings		
Kalaeloa	HI	50%
GWF	CA	50%
Hanford, L. P.	CA	50%
GWF Energy	CA	50%
Bridgewater	NH	40%
Turboven	Venezuela	50%

Energy Holdings also has investments in certain companies in which it does not have the ability to exercise significant influence. Such investments are accounted for under the cost method. As of December 31, 2009 and 2008, the carrying value of these investments aggregated $6 million and $21 million, respectively. Energy Holdings periodically reviews these cost method investments for impairment and adjusts the values accordingly.

Note 8. Available-for-Sale Securities

NDT Funds

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that the NDT Funds meet the formula-based minimum NRC funding requirements.

Power maintains the external master nuclear decommissioning trust which contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power s share of decommissioning costs related to its five nuclear units was estimated at approximately $2.1 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2009 was approximately $204 million and is included in the Asset Retirement Obligation (ARO). The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Funds as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Funds:

	As of December 31, 2009			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 475	$ 180	$ (5)	$ 650
Debt Securities				
Government Obligations	296	4	(3)	297
Other Debt Securities	209	10	(3)	216
Total Debt Securities	505	14	(6)	513
Other Securities	37		(1)	36
Total Available-for-Sale Securities	**$ 1,017**	**$ 194**	**$ (12)**	**$ 1,199**

	As of December 31, 2008			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 386	$ 32	$ (5)	$ 413
Debt Securities				
Government Obligations	192	3		195
Other Debt Securities	284	6		290
Total Debt Securities	476	9		485
Other Securities	72	1	(1)	72
Total Available-for-Sale Securities	**$ 934**	**$ 42**	**$ (6)**	**$ 970**

The following table shows the value of securities in the NDT Funds that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2009 Less Than 12 Months		As of December 31, 2009 Greater Than 12 Months		As of December 31, 2008 Less Than 12 Months*	
	Fair Value	**Gross Unrealized Losses**	**Fair Value**	**Gross Unrealized Losses**	**Fair Value**	**Gross Unrealized Losses**
			Millions			
Equity Securities(A)	$ 61	$ (5)	$	$	$ 85	$ (5)
Debt Securities						
Government Obligations(B)	78	(2)	15	(1)		
Other Debt Securities(C)	59	(3)				
Total Debt Securities	137	(5)	15	(1)		
Other Securities	1	(1)				(1)
Total Available-for-Sale Securities	**$ 199**	**$ (11)**	**$ 15**	**$ (1)**	**$ 85**	**$ (6)**

* There were no gross unrealized losses as of December 31, 2008 for 12 months or longer.

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(A) Equity Securities Investments in marketable equity securities within the NDT fund are primarily investments in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over several hundred companies with limited impairment durations and a severity that is generally less than ten percent of cost. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2009.

(B) Debt Securities (Government) Unrealized losses on Power s NDT investments in US Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the US government or an agency of the US government, it is not expected that these securities will settle for less than their amortized cost basis, assuming Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2009.

(C) Debt Securities (Corporate) Power s investments in corporate bonds are primarily with investment grade securities. It is not expected that these securities would settle at less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2009.

The proceeds from the sales of and the net realized gains on securities in the NDT Funds were:

	Years Ended December 31,		
	2009	**2008**	**2007**
		Millions	
Proceeds from Sales	$ 1,769	$ 3,060	$ 1,672
Net Realized Gains (Losses)			
Gross Realized Gains	$ 183	$ 354	$ 164
Gross Realized Losses	$ (135)	$ (273)	$ (88)
Net Realized Gains	**$ 48**	**$ 81**	**$ 76**

Net realized gains disclosed in the above table were recognized in Other Income and Other Deductions in Power s Consolidated Statement of Operations. Net unrealized gains of $91 million (after-tax) were recognized in Accumulated Other Comprehensive Loss in Power s Consolidated Balance Sheet as of December 31, 2009.

The available-for-sale debt securities held as of December 31, 2009 had the following maturities:

$6 million less than one year,

$87 million after one through five years,

$138 million after five through 10 years, $61 million after 10 through 15 years, and

$7 million after 15 through 20 years, and $214 million over 20 years.

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (OCI). In 2009, other-than-temporary impairments of $60 million were

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recognized on securities in the NDT Funds. Any subsequent recoveries in the value of these securities are recognized in OCI unless the securities are sold, in which case, any gain is recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost detail of the securities.

Rabbi Trusts

PSEG maintains certain unfunded nonqualified benefit plans; assets have been set aside in grantor trusts commonly known as Rabbi Trusts to provide supplemental retirement and deferred compensation benefits to certain key employees.

PSEG classifies investments in the Rabbi Trusts as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trusts.

	As of December 31, 2009			
	Cost	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
	Millions			
Equity Securities	$ 10	$ 3	$	$ 13
Debt Securities	101	21		122
Other Securities	14			14
Total PSEG Available-for-Sale Securities	**$ 125**	**$ 24**	**$**	**$ 149**

	As of December 31, 2008			
	Cost	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
	Millions			
Equity Securities	$ 11	$	$ (2)	$ 9
Debt Securities	102	9	(1)	110
Other Securities	14			14
Total PSEG Available-for-Sale Securities	**$ 127**	**$ 9**	**$ (3)**	**$ 133**

The Rabbi Trusts are invested in commingled indexed mutual funds, in which the shares have the characteristics of equity securities. Due to the commingled nature of these funds, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. In 2009, other-than-temporary impairments of $1 million were recognized on the equity investments of the Rabbi Trusts.

	2009	2008	2007
		Millions	
Proceeds from Sales	$ 2	$ 23	$ 33
Net Realized Losses:			
Gross Realized Gains	$	$ 2	$ 1
Gross Realized Losses	(1)	(2)	(2)
Net Realized Losses	**$ (1)**	**$**	**$ (1)**

The cost of these securities was determined on the basis of specific identification.

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The estimated fair value of the Rabbi Trusts related to PSEG, Power and PSE&G are detailed as follows:

	As of December 31, 2009	As of December 31, 2008
	Millions	
Power	$ 30	$ 27
PSE&G	51	46
Other	68	60
Total PSEG Available-for-Sale Securities	**$ 149**	**$ 133**

Note 9. Goodwill and Other Intangibles

As of each of December 31, 2009 and 2008, Power had goodwill of $16 million related to the Bethlehem Energy Center. Power conducted an annual review for goodwill impairment as of October 31, 2009 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

Energy Holdings pro rata share of goodwill relating to its equity method investment in Kalaeloa was $25 million as of December 31, 2009 and 2008.

In addition to goodwill, as of December 31, 2009 and 2008, Power had intangible assets of $114 million and $43 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense including costs for CO_2 emissions, which is recorded as emissions occur, for the years ended December 31, 2009, 2008 and 2007 amounted to $34 million, $1 million and $2 million, respectively. Expense related to renewable energy requirements, which is recorded as load is served under contracts requiring energy from renewable sources, for the years ended December 31, 2009, 2008 and 2007 amounted to $46 million, $25 million and $16 million, respectively.

Also as of December 31, 2009 and 2008, Energy Holdings joint venture that develops compressed air energy storage had intangible assets of $9 million.

Note 10. Asset Retirement Obligations (AROs)

PSEG, Power and PSE&G have recorded various Asset Retirement Obligations (AROs) which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

Power s ARO liability primarily relates to the decommissioning of its nuclear power plants, an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 8. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power s fossil generation units, including liabilities for

- removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, restoration of leased office space to rentable condition upon lease termination,

permits and authorizations,

restoration of an area occupied by a reservoir when the reservoir is no longer needed, and

demolition of certain plants, and the restoration of the sites at which they reside when the plants are no longer in service.

On December 31, 2009, Power recorded a decrease to its ARO liability and asset of $134 million, primarily related to revisions in assumptions regarding the decommissioning of its nuclear facilities and estimated decommissioning cash flows. These revisions include updates to the discount rate and inflation rate used in estimating future decommissioning cash flows, as well as new information and legal precedent, including

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power s settlement with the DOE during 2009 regarding the reimbursement for costs associated with storage and disposal of spent nuclear fuel. See Note 12. Commitments and Contingent Liabilities for additional information.

PSE&G has a conditional ARO for legal obligations related to the removal of asbestos and underground storage tanks at certain industrial establishments, removal of wood poles, leases and licenses, and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G did not record an ARO for PSE&G s protected steel and poly-based natural gas transmission lines, as management believes that these categories of transmission lines have an indeterminable life.

PSE&G recognized a decrease in its ARO liability and asset of $41 million, primarily relating to a revision in the inflation rate assumption used to calculate the estimated future undiscounted cash flows.

The impact of the revisions to the various assumptions, as well as other changes to the ARO liabilities for PSEG, Power and PSE&G during 2009, are presented in the following table:

	PSEG	**Power**	**PSE&G**	**Other**
		Millions		
ARO Liability as of January 1, 2009	$ 576	$ 334	$ 240	$ 2
Liabilities Settled	(4)	(1)	(3)	
Liabilities Incurred	1		1	
Accretion Expense	27	27		
Accretion Expense Deferred and Recovered in Rate Base (A)	14		14	
Revisions to Present Value of Estimated Cash Flows	(175)	(134)	(41)	
ARO Liability as of December 31, 2009	**$ 439**	**$ 226**	**$ 211**	**$ 2**

(A) Not reflected as expense in Consolidated Statements of Operations

Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and other postretirement benefit plans covering PSEG s and its participating affiliates current and former employees who meet certain eligibility criteria. Eligible employees of Power, PSE&G, Energy Holdings and Services participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG s two defined contribution plans described below.

PSEG, Power and PSE&G are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions were first measured as of December 31, 2006 in compliance with revised accounting guidance effective for periods ending after December 15, 2006 and in accordance with customary practice of each PSEG company. For under funded plans, the liability is equal to the difference between the plan s benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, accounting guidance requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Loss, a separate component of Stockholder s Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses, prior service costs and transition obligations arising from the adoption of the revised accounting guidance for pensions and OPEB, which had not been expensed.

For Power, the charge to Accumulated OCI is amortized and recorded as net periodic pension cost in the Consolidated Statement of Operations. For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statement of Operations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2009 and 2008. It also provides the funded status of the plans and the amounts recognized and amounts not recognized in the Consolidated Balance Sheets at the end of both years.

	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	Millions			
Change in Benefit Obligation:				
Benefit Obligation at Beginning of Year	$ 3,569	$ 3,601	$ 1,104	$ 1,166
Service Cost	76	78	13	15
Interest Cost	235	227	73	72
Actuarial (Gain) Loss	381	(122)	129	(91)
Gross Benefits Paid	(216)	(215)	(69)	(64)
Medicare Subsidy Receipts			5	6
Plan Amendments	(28)			
Benefit Obligation at End of Year	**$ 4,017**	**$ 3,569**	**$ 1,255**	**$ 1,104**
Change in Plan Assets:				
Fair Value of Assets at Beginning of Year	$ 2,364	$ 3,390	$ 129	$ 163
Actual Return on Plan Assets	393	(883)	20	(45)
Employer Contributions	373	72	75	69
Gross Benefits Paid	(216)	(215)	(69)	(64)
Medicare Subsidy Receipts			5	6
Fair Value of Assets at End of Year	**$ 2,914**	**$ 2,364**	**$ 160**	**$ 129**
Funded Status:				
Funded Status (Plan Assets less Benefit Obligation)	**$ (1,103)**	**$ (1,205)**	**$ (1,095)**	**$ (975)**
Additional Amounts Recognized in the Consolidated Balance Sheets:				
Current Accrued Benefit Cost	$ (9)	$ (9)	$	$
Noncurrent Accrued Benefit Cost	(1,094)	(1,196)	(1,095)	(975)
Amounts Recognized	**$ (1,103)**	**$ (1,205)**	**$ (1,095)**	**$ (975)**
Additional Amounts Recognized in Accumulated Other Comprehensive Loss, Regulated Assets and Deferred Assets:				
Net Transition Obligation	$	$	$ 57	$ 85
Prior Service Cost	(3)	32	83	96
Net Actuarial Loss	1,617	1,527	172	48
Total	**$ 1,614**	**$ 1,559**	**$ 312**	**$ 229**

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and other postretirement benefit plans on an aggregate basis. As of December 31, 2009, PSEG has funded approximately 73% of its projected benefit obligation. This percentage does not include $149 million of assets in the Rabbi Trusts as of December 31, 2009, which are used to partially fund the nonqualified pension plans. The fair values of the Rabbi Trust assets are included in the Consolidated Balance Sheets.

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG s defined benefit pension plans was $3.6 billion as of December 31, 2009 and $3.2 billion as of December 31, 2008.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides the components of net periodic benefit cost for the years ended December 31, 2009, 2008 and 2007:

	Pension Benefits			Other Benefits		
	2009	2008	2007	2009	2008	2007
	Millions					
Components of Net Periodic Benefit Costs:						
Service Cost	$ 76	$ 78	$ 83	$ 13	$ 15	$ 16
Interest Cost	235	227	217	73	72	73
Expected Return on Plan Assets	(215)	(290)	(289)	(12)	(15)	(14)
Amortization of Net						
Transition Obligation				27	27	28
Prior Service Cost	7	9	10	13	13	13
Actuarial Loss	113	13	22	(2)	(1)	7
Net Periodic Benefit Cost	$ 216	$ 37	$ 43	$ 112	$ 111	$ 123
Effect of Regulatory Asset				19	19	19
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 216**	**$ 37**	**$ 43**	**$ 131**	**$ 130**	**$ 142**

Pension costs and OPEB costs for PSEG, Power and PSE&G are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2009	2008	2007	2009	2008	2007
	Millions					
Power	$ 65	$ 10	$ 12	$ 11	$ 13	$ 16
PSE&G	120	16	19	116	113	121
Other	31	11	12	4	4	5
Total Benefit Costs	**$ 216**	**$ 37**	**$ 43**	**$ 131**	**$ 130**	**$ 142**

The following table provides the pre-tax changes recognized in Accumulated OCI, Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2009	2008	2009	2008

	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 203	$ 1,051	$ 120	$ (31)
Amortization of Net Actuarial Gain (Loss)	(113)	(13)	3	1
Prior Service Credit in Current Period	(28)			
Amortization of Prior Service Credit	(7)	(9)	(13)	(13)
Amortization of Transition Asset			(27)	(27)
Total	**$ 55**	**$ 1,029**	**$ 83**	**$ (70)**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated OCI, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2010 are as follows:

	Pension Benefits 2010	Other Benefits 2010
	Millions	
Actuarial Loss	$ 122	$ 8
Prior Service Cost	$	$ 13
Transition Obligation	$	$ 27

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2009	2008	2007	2009	2008	2007
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31:						
Discount Rate	5.91%	6.80%	6.50%	5.90%	6.80%	6.50%
Rate of Compensation Increase	4.61%	4.61%	4.69%	4.61%	4.61%	4.69%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31:						
Discount Rate	6.80%	6.50%	6.00%	6.80%	6.50%	6.00%
Expected Return on Plan Assets	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
Rate of Compensation Increase	4.61%	4.69%	4.69%	4.61%	4.69%	4.69%
Assumed Health Care Cost Trend Rates as of December 31:						
Administrative Expense				5.00%	5.00%	5.00%
Dental Costs				6.00%	6.00%	6.00%
Pre-65 Medical Costs						
Immediate Rate				8.50%	8.50%	8.50%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2015	2013	2012
Post-65 Medical Costs						
Immediate Rate				9.50%	9.50%	9.50%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2016	2014	2013
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs:						
					Millions	
Total of Service Cost and Interest Cost				$ 11	$ 10	$ 11
Postretirement Benefit Obligation				$ 137	$ 111	$ 121
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs:						
Total of Service Cost and Interest Cost				$ (9)	$ (8)	$ (9)
Postretirement Benefit Obligation				$ (115)	$ (93)	$ (101)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the trustee and consist of an undivided interest in an investment account of the Master Trust. Effective January 1, 2008, the pension plans and OPEB plans adopted accounting guidance for fair value measurements. See Note 16. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of

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both plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2009, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 95% and 5%, respectively.

The following table presents information about the investments measured at fair value on a recurring basis at December 31, 2009, including the fair value measurements and the levels of inputs used in determining those fair values.

		Recurring Fair Value Measurements as of December 31, 2009		
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
			Millions	
Cash Equivalents(A)	$ 116	$	$ 63	$ 53
Common Stocks(B)				
Commingled US	1,285	1,285		
Commingled International	474	474		
Other	251	251		
Bonds(C)				
Commingled US	17			17
Commingled International	11			11
Government (US & Foreign)	312		312	
Other	469		469	
Pooled Real Estate(D)	102			102
Private Equity(E)	37			37
	$ 3,074	**$ 2,010**	**$ 844**	**$ 220**

(A) Certain cash equivalents included in temporary investment funds are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2), whereas certain other commingled cash equivalents are measured with significant unobservable inputs and assumptions (primarily Level 3).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2). Certain investments in privately held commingled bond funds are valued using broker quotations or using inputs that are not market observable or can not be derived principally from or corroborated by observable market data (primarily Level 3).

(D) The fair value of real estate investments is based on the annual independent appraisals using a cost, sales-comparison or income approach. The investments are also valued internally every quarter by the investment managers based on significant changes in property operations and market conditions (primarily Level 3).

(E) Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity

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securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).

A reconciliation of the beginning and ending balances of the Pension and OPEB Plans Level 3 assets for the year ended December 31, 2009 follows:

	Balance as of January 1, 2009	Purchases/ (Sales)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2009
			Millions		
Cash Equivalents	$ 25	$ 28	$	$	$ 53
Commingled Bonds US	$ 348	$ (352)	$ 29	$ (8)	$ 17
Commingled Bonds International	$ 10	$ 2	$	$ (1)	$ 11
Pooled Real Estate	$ 171	$ 4	$	$ (73)	$ 102
Private Equity	$ 40	$ (2)	$ 1	$ (2)	$ 37

There were no transfers in or out of Level 3 during the year ending December 31, 2009.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2009**	**2008**
Equity Securities	66%	47%
Fixed Income Securities	26%	43%
Real Estate Assets	3%	8%
Other Investments	5%	2%
Total Percentage	100%	100%

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop an optimal portfolio, which is designed to produce the maximum return opportunity per unit of risk. In 2009, PSEG completed its latest asset/liability study. The results from the study indicated that, in order to achieve the optimal risk/return portfolio, target allocations of 70% equity securities and 30% fixed income securities should be maintained. Derivative financial instruments are used by the plans investment managers primarily to rebalance the fixed income/equity allocation of the portfolio and hedge the currency risk component of foreign investments.

The expected long-term rate of return on plan assets was 8.75% as of December 31, 2009. For 2010, the expected long-term rate of return on plan assets was lowered to 8.50%. This expected return was determined based on the study discussed above and considered the plans historical annualized rate of return since inception, which was an annualized return of 9.24%.

Plan Contributions

PSEG may contribute up to $415 million into its pension plans and $11 million into its postretirement healthcare plan for calendar year 2010.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants. Postretirement benefit payments are shown both gross and net of the federal subsidy expected for prescription

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drugs under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The Act provides a nontaxable federal subsidy to employers that provide retiree prescription drug benefits that are equivalent to the benefits of Medicare Part D.

Year	Pension Benefits	Gross OPEB	Other Benefits Medicare Subsidy	Net OPEB
			Millions	
2010	$ 227	$ 76	$ (5)	$ 71
2011	235	80	(6)	74
2012	242	83	(7)	76
2013	250	84	(7)	77
2014	259	87	(8)	79
2015-2019	1,463	463	(47)	416
Total	**$ 2,676**	**$ 873**	**$ (80)**	**$ 793**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act defined contribution plans. Eligible represented employees of Power, PSE&G and Services participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of Power, PSE&G, Energy Holdings and Services participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches certain employee contributions up to 7% for Savings Plan participants and up to 8% for Thrift Plan participants equal to 50% of such employee contributions. The amount paid for employer matching contributions to the plans for PSEG, Power and PSE&G are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2009	2008	2007
		Millions	
Power	$ 10	$ 9	$ 9
PSE&G	17	17	15
Other	5	5	4
Total Employer Matching Contributions	**$ 32**	**$ 31**	**$ 28**

Effective in February 2010, matching contributions were suspended or reduced for certain employee groups. The company match for certain represented employees of Power, PSE&G and Services who participate in the Savings Plan and qualify for benefits under the final average pay pension plan has been suspended while the company match for other represented employees was reduced from 50% to 25% on the first 7% of pay contribution, or not reduced at all. The company match for eligible non-represented employees of Power, PSE&G, Energy Holdings and Services who participate in the Thrift Plan and are eligible for retirement benefits under the qualified final average pay pension plan has been suspended.

Note 12. Commitments and Contingent Liabilities

Guaranteed Obligations

Power s activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash related instruments or guarantees.

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Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be out-of-the-money (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this is highly unlikely. For this reason, the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any margins posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on margin requirements under such contracts, which are posted and received primarily in the form of letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2009 and 2008 are as follows:

	As of December 31,	
	2009	**2008**
	Millions	
Face value of outstanding guarantees	$ 1,783	$ 1,856

Exposure under current guarantees	$ 403	$ 585
Letters of Credit Margin Posted	$ 122	$ 201
Letters of Credit Margin Received	$ 123	$ 250
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$	$ 3
Counterparty Cash Margin Received	(90)	(81)
Net Broker Balance Received	(31)	(74)

Power nets the fair value of cash collateral receivables and payables with the corresponding net energy contract balances. See Note 15. Financial Risk Management Activities for further discussion. The remaining balance of net cash (received) deposited is primarily included in Accounts Payable.

In the event of a deterioration of Power s credit rating to below investment grade, which would represent a two level downgrade from its current ratings, many of these agreements allow the counterparty to demand

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further performance assurance. As of December 31, 2009, if Power were to lose its investment grade rating, additional collateral of approximately $986 million could be required. As of December 31, 2009, there was $2.4 billion of available liquidity under PSEG and Power s credit facilities that could be used to post collateral.

In addition to amounts discussed above, Power had posted $52 million and $101 million in letters of credit as of December 31, 2009 and 2008, respectively, to support various other contractual and environmental obligations.

Environmental Matters

Passaic River

Historic operations by PSEG companies along the Passaic and Hackensack rivers, and the operations of dozens of other companies, are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a six-mile stretch of the Passaic River in the area of Newark, New Jersey is a facility within the meaning of that term under CERCLA. The EPA later expanded its study area to include the entire 17-mile tidal reach of the lower Passaic River.

PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the river. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former Manufactured Gas Plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA believes that hazardous substances were released from the Essex Site and one of PSE&G s former MGP locations (Harrison Site). In 2006, the EPA notified the potentially responsible parties (PRPs) that the cost of its study would greatly exceed the original estimated cost of $20 million. 73 PRPs, including Power and PSE&G, agreed to assume responsibility for the study and to divide the associated costs according to a mutually agreed-upon formula. The PRP group is presently executing the study. Approximately five percent of the study costs are attributable to PSE&G s former MGP sites and approximately one percent to Power s generating stations. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft Focused Feasibility Study that proposes six options to address the contamination cleanup of the lower eight miles of the Passaic River, with estimated costs from $900 million to $2.3 billion. The work contemplated by the study is not subject to the cost sharing agreement discussed above. A revised focused feasibility study is expected to be released in 2010.

In June 2008, an agreement was announced between the EPA and two PRPs for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. The two PRPs have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP s discharge of hazardous substances into the Passaic River. In February 2009, third-party complaints were filed against some 320 third-party defendants, including Power and PSE&G, claiming that each of the third-party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances they allegedly discharged into the Passaic River. The third-party complaints seek statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third-party complaints and will vigorously assert those defenses.

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Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the NJ Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In November 2008, PSEG and a number of other PRPs agreed in an interim cooperative assessment agreement to pay an aggregate of $1 million for past costs incurred by the Federal trustees, and certain costs the trustees will incur going forward, and to work with the trustees for a 12-month period to explore whether some or all of the trustees claims can be resolved in a cooperative fashion. That initial 12-month period ended in December 2009 and it is presently uncertain whether that effort will continue in 2010.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact Occidental Chemical Corporation (OCC) to discuss participating in the Remedial Investigation/Feasibility Study that OCC was conducting. The notice stated the EPA s belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG is participating in and partially funding this study.

PSEG, Power and PSE&G cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to the Passaic River, the NJDEP Litigation, the Newark Bay Study Area or with respect to natural resource damages claims; however, such costs could be material.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at PSE&G s former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. The NJDEP has also announced initiatives to accelerate the investigation and subsequent remediation of the riverbeds underlying surface water bodies that have been impacted by hazardous substances from adjoining sites. In 2005, the NJDEP initiated a program on the Delaware River aimed at identifying the 10 most significant sites for cleanup. One of the sites identified was PSE&G s former Camden Coke facility.

During the second quarter of 2009, PSE&G updated the estimated cost to remediate all MGP sites to completion and determined that the cost to completion could range between $704 million and $804 million from June 30, 2009 through 2021. Since no amount within the range was considered to be most likely, PSE&G reflected a liability of $704 million in its Consolidated Balance Sheet as of June 30, 2009. During the third and fourth quarters of 2009, PSE&G had $10 million of expenditures, reducing the liability to $694 million as of December 31, 2009. Of this amount, $42 million was recorded in Other Current Liabilities and $652 million was reflected as Environmental Costs in Noncurrent Liabilities. As such, PSE&G has recorded a $694 million Regulatory Asset with respect to these costs.

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

The PSD/NSR regulations, promulgated under the Clean Air Act, 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 that are not in compliance with the PSD/NSR regulations to install the best available

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control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In November 2006, Power reached an agreement with the EPA and the NJDEP to achieve emissions reductions targets at certain of Power s generating stations. Under this agreement, Power was required to undertake a number of technology projects, plant modifications and operating procedure changes at Hudson and Mercer designed to meet targeted reductions in emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter and mercury. The remaining projects necessary to implement this program are expected to be completed by the end of 2010 at an estimated cost of $200 million to $250 million for Mercer and $750 million to $800 million for Hudson, of which $730 million has been spent on both projects as of December 31, 2009.

In January 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were made at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the Clean Air Act. The notice of violation states that the EPA may issue an order requiring compliance with the relevant Clean Air Act provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Mercury Regulation

In 2005, the EPA established a limit for nickel emissions from oil-fired electric generating units and a cap-and-trade program for mercury emissions from coal-fired electric generating units.

In 2008, the United States Court of Appeals for the District of Columbia Circuit rejected the EPA s mercury emissions program and required the EPA to develop standards for mercury and nickel emissions that adhere to the Maximum Available Control Technology (MACT) provisions of the Clean Air Act. In 2009, the EPA indicated that it intended to move forward with a rule-making process to develop MACT standards consistent with the Court s ruling and agreed to finalize them by November 2011.

The full impact to PSEG of these developments is uncertain. It is expected that new MACT requirements will require more stringent control than the cap-and-trade program struck down by the D.C. Circuit Court; however, the costs of compliance with mercury MACT standards will have to be compared with the existing state mercury-control requirements, as described below.

Pennsylvania

In 2007, Pennsylvania finalized its state-specific requirements to reduce mercury emissions from coal-fired electric generating units. These requirements were more stringent than the EPA s vacated Clean Air Mercury Rule but not as stringent as would be required by a MACT process. In 2009, the Commonwealth Court of Pennsylvania struck down the state rule, indicating that the rule violated Pennsylvania law because it is inconsistent with the Clean Air Act. On December 23, 2009, the Commonwealth Court s decision was affirmed by the Supreme Court of Pennsylvania. Unless the law in Pennsylvania is changed requiring the regulation of mercury by the PA DEP, then our Pennsylvania generating stations likely will be subject to regulation under the EPA s MACT rule. It is uncertain whether the Keystone and Conemaugh generating stations will be able to achieve the necessary reductions at these stations with currently planned capital projects under a MACT regulation.

Connecticut

Mercury emissions control standards were effective in July 2008 and require coal-fired power plants to achieve either an emissions limit or 90% mercury removal efficiency through technology installed to control mercury emissions. With the recently installed activated carbon injection and baghouse at Bridgeport Unit 3, it has demonstrated that it complies with the mercury limits in these standards.

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New Jersey

New Jersey regulations required coal-fired electric generating units to meet certain emissions limits or reduce mercury emissions by approximately 90% by December 15, 2007. Companies that are parties to multi-pollutant reduction agreements, such as Power, have been permitted to postpone such reductions on half of their coal-fired electric generating capacity until December 15, 2012.

Power has achieved or will achieve the required reductions with mercury-control technologies that are part of Power s multi-pollutant reduction agreement that resolved issues arising out of the PSD/NSR air pollution control programs discussed above.

NO_x Reduction

New Jersey

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule will have a significant impact on Power s generation fleet, as it imposes NO_x emissions limits that will likely require the retirement of up to 102 combustion turbines (approximately 2,000 MW) and five older New Jersey steam electric generation units (approximately 800 MW) by April 30, 2015.

Power has been working with the NJDEP throughout the development of this rulemaking to minimize financial impact and to provide for transitional lead time for it to address the retirement of electric generation units. Power cannot predict the financial impact resulting from compliance with this rulemaking.

Connecticut

Under current Connecticut regulations, Power s Bridgeport and New Haven facilities utilize Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities operating permits. Power s agreements with the State of Connecticut authorizing the DERC s expire on May 1, 2010. If not extended, Power could potentially be forced to utilize lower NO_x producing fuels, or install NO_x emission controls in order to operate the units. Power cannot predict the financial impact of such costs, but such costs could be material and could impact the continued viability of these units.

New Jersey Industrial Site Recovery Act (ISRA)

Potential environmental liabilities related to the alleged discharge of hazardous substances at certain generating stations have been identified. In the second quarter of 1999, in anticipation of the transfer of PSE&G s generation-related assets to Power, a study was conducted pursuant to ISRA, which applied to the sale of certain assets. Power had a $50 million liability as of December 31, 2009 and 2008 related to these obligations, which is included in Environmental Costs in Power s and PSEG s Consolidated Balance Sheets.

Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), New Jersey Pollutant Discharge Elimination System (NPDES) permits expire within 5 years of their effective date. In order to renew these permits, but allow the plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. Power has filed or will be filing permit applications for permits in a variety of states that require discharge.

Pursuant to a consent decree with environmental groups, the EPA was required to promulgate rules governing cooling water intake structures under Section 316(b) of the FWPCA. In 2004, the EPA published a rule which did not mandate the use of cooling towers at large existing generating plants. Rather, the rule provided alternatives for compliance with 316(b), including the use of restoration efforts to mitigate for the potential effects of cooling water intake structures, as well as the use of site-specific analysis to determine the best technology available for minimizing adverse impact based upon a cost-benefit test. Power has used restoration and/or a site-specific cost-benefit test in applications filed to renew the permits at its once-through cooled plants, including Salem, Hudson and Mercer.

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One of the most significant NPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the Phase II 316(b) rules published in 2004, which govern cooling water intake structures at large electric generating facilities. Power had historically used restoration and/or a site-specific cost-benefit test in applications it had filed to renew the permits at its once-through cooled plants, including Salem, Hudson and Mercer. However, the new 316(b) rules also would also have been applicable to Bridgeport, and possibly, Sewaren and New Haven stations. In addition to the Salem renewal application, permit renewal applications have been submitted to the NJDEP for Hudson and Sewaren, and to the Connecticut Department of Environmental Protection for Bridgeport.

Portions of the 316(b) rule were challenged by certain northeast states, environmentalists and industry groups. In January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision that remanded major portions of the regulations and determined that Section 316(b) of the FWPCA does not support the use of restoration and the site-specific cost-benefit test. Industry groups, including Power, requested review by the U.S. Supreme Court, which granted review in April 2008. On April 1, 2009, the U.S. Supreme Court reversed the Second Circuit s opinion, concluding that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations. The Supreme Court s decision became effective on April 27, 2009, and the matter was sent back to the Second Circuit for further proceedings consistent with the Supreme Court s opinion. On September 29, 2009, the Second Circuit issued an order remanding the matter to the EPA in light of the Supreme Court s opinion.

The Supreme Court s ruling allows the EPA to continue to use the site-specific cost-benefit test in determining best technology available for minimizing adverse environmental impact. However, the results of further proceedings on this matter could have a material impact on Power s ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power s once-through cooled plants could be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power s application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power s share would have been approximately $575 million. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power s forecasted capital expenditures.

The EPA anticipates proposing a rule in September 2010, and publishing a final rule in July 2012. Until a new rule governing cooling water intake structures at existing power generating stations is finalized, EPA and states implementing the FWPCA have been instructed to issue permits on a case-by-case basis using the agency s best professional judgment.

In January 2010, the NJDEP issued a draft NJPDES permit to another company which would require the installation of closed-cycle cooling at that company s nuclear generating station located in New Jersey. The draft permit is subject to public comment and review prior to being finalized by the NJDEP. We can not predict at this time the final outcome of NJDEP s decision and the impact, if any, such a decision would have on any of Power s once-through cooled generating stations.

Stormwater

In October 2008, the NJDEP notified Power that it must apply for an individual stormwater discharge permit for its Hudson generating station. Hudson stores its coal in an open air pile and, as a result, it is exposed to precipitation. Discharge of stormwater from Hudson has been regulated pursuant to a Basic Industrial Stormwater General Permit, authorization of which has been previously approved by the NJDEP. The NJDEP

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has determined that Hudson is no longer eligible to utilize this general permit and must apply for an individual NJPDES permit for stormwater discharges. While the full extent of these requirements remains unclear, to the extent Power may be required to reduce or eliminate the exposure of coal to stormwater, or be required to construct technologies preventing the discharge of stormwater to surface water or groundwater, those costs could be material.

New Generation and Development

Nuclear

Power has approved the expenditure of approximately $192 million for a steam path retrofit and related upgrades at Peach Bottom Units 2 and 3. Completion of these upgrades is expected to result in an increase of Power s share of nominal capacity by 32 MW (14 MW at Unit 3 in 2011 and 18 MW at Unit 2 in 2012). Total expenditures through December 31, 2009 are $27 million and are expected to continue through 2012. We anticipate expenditures in pursuit of additional output through an extended power up-rate of our co-owned Peach Bottom nuclear plants. The up-rate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Our share of the increased capacity is expected to be 133 MW with an anticipated cost of approximately $400 million.

Connecticut

Power has been selected by the Connecticut Department of Public Utility Control in a regulatory process to build 130 MW of gas-fired peaking capacity. Final approval has been received and construction is expected to commence in June 2011. The project is expected to be in-service by June 2012. Power estimates the cost of these generating units to be $130 million to $140 million. Total capitalized expenditures through December 31, 2009 are $13 million, which are included in Property, Plant and Equipment in the Consolidated Balance Sheets of PSEG and Power.

PJM Interconnection L.L.C. (PJM)

Power plans to construct 178 MW of gas-fired peaking capacity at the Kearny site. This capacity was bid into and has cleared the PJM RPM base residual capacity auction for the 2012-2013 period. Final approval has been received and construction is expected to commence in the second quarter of 2011. The project is expected to be in-service by June 2012. Power estimates the cost of these generating units to be $160 million to $200 million. Total capitalized expenditures through December 31, 2009 are $8 million which are included in Property, Plant and Equipment in Power s and PSEG s Consolidated Balance Sheets.

PSE&G Solar

In January 2010, PSE&G announced that it has entered into contracts with four developers for 12 MW of solar capacity to be developed on land it owns in Edison, Linden, Trenton and Hamilton. The projects represent an investment of approximately $50 million. Construction is expected to start in the second quarter of 2010 pending receipt of all approvals.

Solar Source

Energy Holdings has developed a solar project in western New Jersey and has acquired two additional solar projects currently under construction in Florida and Ohio, which together have a total capacity of approximately 29 MW. Completion of the additional projects is expected by the end of 2010. Energy Holdings has issued guarantees of up to $58 million for payment of obligations related to the construction of these two projects. These guarantees will terminate upon successful completion of the projects. The total investment for the three projects will be approximately $114 million.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third-party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters

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into the Supplier Master Agreement (SMA) with the winners of these BGS auctions following the BPU s approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G s load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey s renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above. In addition to the BGS-related contracts, Power also enters into firm supply contracts with EDCs, as well as other firm sales and commitments.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year			
	2007	**2008**	**2009**	**2010**
36-Month Terms Ending	May 2010	May 2011	May 2012	May 2013(a)
Load (MW)	2,758	2,800	2,900	2,800
$ per kWh	0.09888	0.11150	0.10372	0.09577

(a) Prices set in the 2010 BGS auction become effective on June 1, 2010 when the 2007 BGS auction agreements expire.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G s gas customers. The contract extends through March 31, 2012, and year-to-year thereafter. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. For additional information, see Note 22. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal and oil to support its fossil generation stations and for supply of nuclear fuel for the Salem and Hope Creek nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power s various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power s strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

Power s strategy is to maintain certain levels of uranium concentrates and uranium hexafluoride in inventory and to make periodic purchases to support such levels. As such, the commitments referred to below include estimated quantities to be purchased that are in excess of contractual minimum quantities.

Power s nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2011 and a portion for 2012, 2013 and 2014 at Salem, Hope Creek and Peach Bottom.

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As of December 31, 2009, the total minimum purchase requirements included in these commitments are as follows:

Fuel Type	Commitments through 2014	Power s Share
	Millions	
Nuclear Fuel		
Uranium	$ 725	$ 441
Enrichment	$ 488	$ 309
Fabrication	$ 215	$ 138
Natural Gas	$ 950	$ 950
Coal/Oil	$ 858	$ 858

Included in the $858 million commitment for coal and oil above is $520 million related to a certain coal contract under which Power can cancel contractual deliveries at minimal cost. Through December 2009, Power has cancelled 1.8 million tons of coal and shipments related to that coal at a total cost of approximately $18 million.

The Texas generation facilities also have a contract for low BTU content gas commencing in late 2009 with a term of 15 years and a minimum volume of approximately 13 MMbtu s per year. The gas must meet an availability and quality specification. Power has the right to cancel delivery of the gas at a minimal cost.

Nuclear Fuel Disposal

The Federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. Under the contracts, the US Department of Energy (DOE) was required to begin taking possession of the spent nuclear fuel by no later than 1998. In January 2010, the Federal government announced the formation of a group to study and provide recommendations for a long-term resolution of the nuclear waste issue. Given the uncertainty of the timing and nature of the recommendations, it is not clear when the government will begin taking possession of the spent nuclear fuel.

In September 2009, Power signed an agreement with the DOE applicable to Salem and Hope Creek under which it will be reimbursed for past and future reasonable and allowable costs resulting from the DOE s delay in accepting spent nuclear fuel for permanent disposition. Under this settlement, in October 2009, Power received approximately $47 million for its spent fuel management costs incurred through December 2007 and, in January 2010, received approximately $7 million for costs incurred during 2008. A similar settlement agreement was reached related to Peach Bottom in 2004. The majority of this amount is related to the recovery of the capitalized costs of building on-site storage and related improvements, therefore nearly all of this payment will result in a reduction of previously capitalized plant-related costs rather than an increase in earnings. Power has on-site storage facilities that are expected to satisfy its storage needs through current licensed lives plus an additional twenty years of operation.

Regulatory Proceedings

Competition Act

In April 2007, PSE&G and Transition Funding were served with a purported class action complaint (Complaint) in New Jersey Superior Court challenging the constitutional validity of certain stranded cost recovery provisions of the Competition Act, seeking injunctive relief against continued collection from PSE&G s electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional.

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In July 2007, the plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes as well as recovery of such taxes previously collected. In July 2007, PSE&G filed a motion to dismiss the amended Complaint, which was granted in October 2007. In November 2007, the plaintiff filed a notice of appeal with the Appellate Division of the New Jersey Superior Court. In February 2009, the New Jersey Appellate Division affirmed the decision of the lower court dismissing the case. In May 2009 the New Jersey Supreme Court denied a request from the plaintiff to review the Appellate Division s decision.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same stranded cost charges. In September 2007, PSE&G filed a motion with the BPU to dismiss the petition, which remains pending. PSE&G cannot predict the outcome of the action pending at the BPU.

BPU Deferral Audit

The BPU Energy and Audit Division conducts audits of deferred balances under various adjustment clauses. A draft Deferral Audit Phase II report relating to the 12-month period ended July 31, 2003 was released to the BPU in April 2005.

That report, which addresses SBC, Market Transition Charge (MTC) and non-utility generation (NUG) deferred balances, found that the Phase II deferral balances complied in all material respects with applicable BPU Orders. It also noted that the BPU Staff had raised certain questions with respect to the reconciliation method PSE&G had employed in calculating the overrecovery of its MTC and other charges during the Phase I and Phase II four-year transition period. The matter was referred to the Office of Administrative Law. The amount in dispute is $114 million, which if required to be refunded to customers with interest through December 2009, would be $142 million.

In January 2009, the administrative law judge (ALJ) issued a decision which upheld PSE&G s central contention that the 2004 BPU Order approving the Phase I settlement resolved the issues being raised by the Staff and the NJ Division of Rate Counsel, and that these issues should not be subject to re-litigation in respect of the first three years of the transition period. The ALJ s decision stated that the BPU could elect to convene a separate proceeding to address the fourth and final year reconciliation of MTC recoveries. The amount in dispute with respect to this Phase II period is approximately $50 million.

By order dated September 3, 2009, the BPU rejected the ALJ s initial decision, elected to maintain jurisdiction over the matter and established a schedule for briefing on the merits of the question whether any MTC-related refunds are due. Generally, the BPU rejected the claims that the matters at issue had been fairly and finally litigated. Briefing has been completed and the matter is now pending before the BPU.

New Jersey Clean Energy Program

In 2008, the BPU approved funding requirements for each New Jersey utility applicable to its Renewable Energy and Energy Efficiency programs for the years 2009 to 2012. The aggregate funding amount is $1.2 billion for all years. PSE&G s share of the $1.2 billion program is $705 million. PSE&G has recorded a discounted liability of $566 million as of December 31, 2009. Of this amount, $166 million was recorded as a current liability and $400 million as a noncurrent liability. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are expected to be recovered from PSE&G ratepayers through the SBC.

Leveraged Lease Investments

The Internal Revenue Service (IRS) has issued reports with respect to its audits of PSEG s federal corporate income tax returns for tax years 1997 through 2003, which disallowed all deductions associated with certain lease transactions. The IRS reports also proposed a 20% penalty for substantial understatement of tax liability. PSEG has filed protests of these findings with the Office of Appeals of the IRS.

PSEG believes its tax position related to these transactions was proper based on applicable statutes, regulations and case law in effect at the time that the deductions were taken. There are several pending tax cases involving other taxpayers with similar leveraged lease investments. To date, six cases have been decided at the trial court level, four of which were decided in favor of the government. An appeal of one of these decisions was

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affirmed. The fifth case involves a jury verdict that was challenged by both parties on inconsistency grounds but was later settled by the parties. One case, involving an investment in an energy transaction by a utility, was decided in favor of the taxpayer.

In order to reduce the cash tax exposure related to these leases, Energy Holdings is pursuing opportunities to terminate international leases with lessees that are willing to meet certain economic thresholds. Energy Holdings has terminated 12 of these leasing transactions in 2009 and one in December 2008 and reduced the related cash tax exposure by $670 million. As of December 31, 2009 and December 31, 2008, PSEG s total gross investment in such transactions was $347 million and $1 billion respectively. Energy Holdings terminated one more of these lease transactions in January 2010.

Cash Impact

As of December 31, 2009, an aggregate of approximately $660 million would become currently payable if PSEG conceded all deductions taken through that date. PSEG has deposited $320 million with the IRS to defray potential interest costs associated with this disputed tax liability, reducing its potential cash exposure to $340 million. In the event PSEG is successful in defense of its position, the deposit is fully refundable with interest. If the IRS is successful in a litigated case consistent with the positions it has taken in the generic settlement offer recently proposed, an additional $80 million to $100 million of tax would be due for tax positions through December 31, 2009.

As of December 31, 2009, penalties of $150 million would also become payable if the IRS successfully asserted and litigated a case against PSEG. PSEG has not established a reserve for penalties because it believes it has strong defenses to the assertion of penalties under applicable law. Interest and penalty exposure will grow at the rate of $4 million per quarter during 2010.

PSEG currently anticipates that it may be required to pay between $110 million and $290 million in tax, interest and penalties for the tax years 1997-2000 during 2010 and subsequently commence litigation to recover these amounts. Further it is possible that an additional payment of between $220 million and $510 million could be required during 2010 for tax years 2001-2003 followed by further litigation to recover those taxes. These amounts are in addition to tax deposits already made.

Earnings Impact

As a result of the outcomes of various court cases during 2009 and input from ongoing negotiations with the IRS, PSEG adjusted its measurement of uncertain tax positions in December of 2009. Due to changes in the timing of projected cash flows related to these leases, PSEG recalculated its lease transactions and recorded an after-tax charge of $23 million. This charge was reflected as a reduction in Operating Revenues of $25 million with a partially offsetting reduction in Income Tax Expense of $2 million. Offsetting this impact, PSEG reduced its reserve for IRS interest by $52 million, after tax. This number also includes a small change due to the impact of the termination of leases. The net impact of these two adjustments was an after-tax increase to earnings of $29 million. The current reserve position represents PSEG s view of the earnings impact that could result from a settlement related to these transactions, although a total loss, consistent with the broad settlement offer proposed by the IRS, would result in an additional earnings charge of $130 million to $150 million. The actions described above concerning the leveraged lease investments are not expected to violate any covenant or result in a default under the Energy Holdings Senior Notes indenture.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the primary property and decontamination liability insurance at Salem, Hope Creek and Peach Bottom. NEIL also provides excess property insurance through its decontamination liability, decommissioning liability and excess property policy and replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power s maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit, or issues a confirmatory order keeping such unit down.

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The American Nuclear Insurers (ANI) and NEIL policies both include coverage for claims arising out of acts of terrorism. NEIL makes a distinction between certified and non-certified acts of terrorism, as defined under the Terrorism Risk Insurance Act (TRIA), and thus its policies respond accordingly. For non-certified acts of terrorism, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus any amounts available through reinsurance or indemnity for non-certified acts of terrorism. For any act of terrorism, Power s nuclear liability policies will respond similarly to other covered events. For certified acts, Power s nuclear property NEIL policies will respond similarly to other covered events.

The Price-Anderson Act sets the limit of liability for claims that could arise from an incident involving any licensed nuclear facility in the U.S. The limit of liability is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current limit of liability is $12.6 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each party with an ownership interest in a nuclear reactor can be assessed its share of $118 million per reactor per incident, payable at $18 million per reactor per incident per year. If the damages exceed the limit of liability, the President is to submit to Congress a plan for providing additional compensation to the injured parties. Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power s maximum aggregate assessment per incident is $370 million (based on Power s ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $55 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power s insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage	Retrospective Assessments
	Millions	
Public and Nuclear Worker Liability (Primary Layer):		
ANI	$ 375(A)	$
Nuclear Liability (Excess Layer):		
Price-Anderson Act	12,219(B)	370
Nuclear Liability Total	$ 12,594(C)	$ 370
Property Damage (Primary Layer):		
NEIL		
Primary (Salem/Hope Creek/Peach Bottom).	$ 500	$ 17
Property Damage (Excess Layers):		
NEIL II (Salem/Hope Creek/Peach Bottom)	750	8
NEIL Blanket Excess (Salem/Hope Creek/Peach Bottom)	850(D)	5
Property Damage Total (Per Site)	$ 2,100	$ 30
Accidental Outage:		
NEIL I (Peach Bottom)	$ 245(E)	$ 6
NEIL I (Salem)	281(E)	7
NEIL I (Hope Creek)	490(E)	6

Replacement Power Total	$ 1,016	$ 19

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from workers claiming exposure to the

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hazard of nuclear radiation. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion. This limit was increased from $300 million to $375 million effective January 1, 2010.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the U.S. that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of October 29, 2008. The next adjustment is due on or before October 29, 2013. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D) For property limits in excess of $1.25 billion, Power participates in a Blanket Limit policy where the $850 million limit is shared by Power with Exelon Generation among the Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 facilities owned by Exelon Generation and the Peach Bottom, Salem and Hope Creek facilities. This limit is not subject to reinstatement in the event of a loss. Participation in this program materially reduces Power s premium and the associated potential assessment.

(E) Peach Bottom has an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem has an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 75 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Minimum Lease Payments

PSEG and Power have entered into capital leases for administrative office space. The total future minimum payments and present value of these capital leases as of December 31, 2009 are:

	Power	Other
	Millions	
2010	$ 1	$ 7
2011	1	7
2012	2	8
2013	2	7
2014	2	7
Thereafter	1	6
Total Minimum Lease Payments	9	42
Less: Imputed Interest	(1)	(12)
Present Value of Net Minimum Lease Payments	$ 8	$ 30

PSE&G has leased administrative office space under various operating leases. Total future minimum lease payments as of December 31, 2009 are $16 million.

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Note 13. Schedule of Consolidated Debt

Long-Term Debt

	Maturity	As of December 31, 2009	2008
		Millions	
PSEG (Parent)			
Senior Note 6.89%	2009	$	$ 49
Senior Note 4.66%	2009		200
Principal Amount Outstanding			249
Fair Value of Swaps(A)		(3)	
Unamortized Discount Related to Debt Exchange(B)		(35)	
Amounts Due Within One Year			(249)
Total Long-Term Debt of PSEG (Parent)		**$ (38)**	**$**

	Maturity	As of December 31, 2009	2008
Power		Millions	
Senior Notes:			
3.75%	2009	$	$ 250
7.75%	2011	800	800
6.95%	2012	600	600
5.00%	2014	250	250
5.50%	2015	300	300
5.32%	2016	303	
8.63%	2031	500	500
Total Senior Notes		2,753	2,700
Pollution Control Notes:			
5.00%	2012	66	66
5.50%	2020	14	14
5.85%	2027	19	19
5.75%	2031	25	25
5.75%	2037	40	40
4.00%	2042		44
Total Pollution Control Notes		164	208

Medium Term Notes (MTNs):			
6.00%	2013	48	
6.50%	2014	161	
Total MTNs		209	
Nonrecourse Project Debt - Texas - Floating Rate(C)(D)	2009		280
Principal Amount Outstanding		3,126	3,188
Amounts Due Within One Year			(530)
Net Unamortized Discount		(5)	(5)
Total Long-Term Debt of Power		**$ 3,121**	**$ 2,653**

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PSE&G	**Maturity**	**As of December 31, 2009**	**2008**
First and Refunding Mortgage Bonds(E):		Millions	
Libor + .875%	2010	300	300
6.75%	2016	171	171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		620	620
Pollution Control Bonds(E):			
6.45%	2019		5
5.20%	2025	23	23
Floating Rate(F)	2028 - 2033		100
5.45%	2032	50	50
6.40%	2032	100	100
Total Pollution Control Bonds		173	278
Medium-Term Notes(E):			
8.16%	2009		16
8.10%	2009		44
5.13%	2012	300	300
5.00%	2013	150	150
5.38%	2013	300	300
6.33%	2013	275	275
5.00%	2014	250	250
5.30%	2018	400	400
7.04%	2020	9	9
7.18%	2023		5
7.15%	2023		34
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	
Total MTNs		2,784	2,633
Principal Amount Outstanding		3,577	3,531
Amounts Due Within One Year		(300)	(60)
Net Unamortized Discount		(6)	(8)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**3,271**	**3,463**

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	Maturity	As of December 31, 2009	2008
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
Swap to 5.66%	2009		82
6.45%	2011	232	328
6.61%	2013	454	454
6.75%	2014	220	220
6.89%	2015	370	370
Principal Amount Outstanding		1,276	1,454
Amounts Due Within One Year		(186)	(178)
Total Securitization Debt of Transition Funding		**1,090**	**1,276**
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.34%	2009 - 2012	24	33
4.49%	2013	20	20
4.57%	2015	23	23
Principal Amount Outstanding		67	76
Amounts Due Within One Year		(12)	(10)
Total Securitization Debt of Transition Funding II		**55**	**66**
Total Long-Term Debt of PSE&G		**$ 4,416**	**$ 4,805**

Energy Holdings	Maturity	As of December 31, 2009	2008
		Millions	
8.50% Senior Notes	2011	$ 127	$ 505
Non-Recourse Project Debt(D):			
Resources 4.75% to 8.75%	2009 - 2016	30	33
EGDC 8.27%	2009 - 2013	12	15
Principal Amount Outstanding		42	48
Amounts Due Within One Year		(23)	(6)
Total Non-Recourse Project Debt		19	42
Total Long-Term Debt of Energy Holdings		**$ 146**	**$ 547**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt in the Consolidated Balance Sheet. For additional information, see Note 15. Financial Risk Management Activities.

(B) Represents the unamortized premium paid for the debt exchange between Power and Energy Holdings that is deferred at the PSEG parent level since the debt exchange was between two subsidiaries of the same parent company, as discussed below.

(C) The floating rates consisted of 3 month Libor plus 2.38% and 3 month Libor plus 3.25% as of December 31, 2008.

(D) Non-recourse financing transactions consist of loans from banks and other lenders that are typically secured by project assets and cash flows and generally impose no material obligation on the parent-

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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.

(E) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(F) The coupon rate ranged from 0.75% to 1.25% as of December 31, 2008. The coupon rate for $50 million reset on a weekly basis whereas the coupon rates for the other $50 million were in commercial paper mode and therefore changed from time to time.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2009 are as follows:

Year	PSEG (Parent)	Power	PSE&G	PSE&G Transition Funding	Transition Funding II	Energy Holdings Senior Notes	Energy Holdings Non-Recourse Debt	Total
					Millions			
2010	$	$	$ 300	$ 186	$ 12	$	$ 23	$ 521
2011		800		195	11	127	3	1,136
2012		666	300	205	12		4	1,187
2013		48	725	214	12		3	1,002
2014		411	250	225	12		1	899
Thereafter		1,201	2,002	251	8		8	3,470
	$	**$ 3,126**	**$ 3,577**	**$ 1,276**	**$ 67**	**$ 127**	**$ 42**	**$ 8,215**

Long-Term Debt Financing Transactions

Power and Energy Holdings

In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Under this transaction, an aggregate principal amount of $368 million, or 74% of Energy Holdings Senior Notes, was exchanged for total consideration from Power of $404 million. The $404 million was comprised of $303 million of newly issued 5.32% Senior Notes due September 2016 and cash payments of $101 million. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium of $36 million was deferred and will be amortized over the term of the newly issued debt. The deferred amount is reflected as an offset to Long-Term Debt on PSEG s Consolidated Balance Sheet. In October 2009, Power distributed to PSEG its receivable from Energy Holdings related to the exchange. PSEG then contributed such receivable to Energy Holdings to offset Energy Holdings payable to Power related to the debt exchange transaction.

Energy Holdings has $127 million of 8.50% Senior Notes due 2011 still outstanding as of December 31, 2009.

During 2009, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions in addition to the debt exchange.

PSEG

paid $200 million of 4.66% Senior Notes at maturity in September, and

paid $49 million of 6.89% Senior Notes at maturity in October.

Power

redeemed $280 million of floating rate non-recourse project debt due in December 2009 associated with PSEG Texas, and

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$44 million of its senior Notes servicing and securing the 4.00% Pollution Control Bonds of the Pennsylvania Economic Development Authority (PEDFA) were converted to variable rate in January 2009 when the PEDFA Bonds were converted to variable rate demand bonds. Power reacquired the PEDFA Bonds in December 2009 and, in January 2010, Power caused the PEDFA Bonds to be converted from Alternative Minimum Tax (AMT) to non-AMT status and to be remarketed as variable rate demand bonds backed by letter of credit.

established a program for the issuance of up to $500 million of unsecured medium-term notes (MTNs) to retail investors in January. Under this program it

¡ issued $161 million of 6.5% MTNs due January 2014 (issued January, callable in one year), and

¡ issued $48 million of 6% MTNs due January 2013 (issued January, callable in one year).

paid $250 million of 3.75% Senior Notes at maturity in April.

PSE&G

paid $44 million of 8.10% MTNs, Series A at maturity in May,

paid $16 million of 8.16% MTNs, Series A at maturity in May,

paid $177 million of Transition Funding s securitization debt,

paid $10 million of Transition Funding II s securitization debt,

purchased $100 million (Series 2003 B-1 and 2003 B-2) of tax-exempt variable rate bonds of the Pollution Control Financing Authority of Salem County (Salem County Authority Bonds). These bonds are serviced and secured by like principal amount of PSE&G s pollution control Mortgage Bonds and were held by the broker/dealer or tendered by bondholders upon the mandatory tender in October 2009,

issued $250 million of 5.375% MTNs, Series G due November 2039, in November, and

redeemed $34 million of 7.15% MTNs, Series A due August 2023, $5 million of 7.18% MTNs, Series A due August 2023, and $5 million of 6.45% Pollution Control Series T due October 2019 in December.

Energy Holdings

repurchased $10 million of its 8.5% Senior Notes due 2011, and

paid a total of $6 million of non-recourse project debt.

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Short-Term Liquidity

As of December 31, 2009, PSEG, Power and PSE&G had the following credit facilities. Each of the facilities is restricted as to availability and use to the specific companies as listed below. PSEG, Power and PSE&G each believes sufficient liquidity exists to fund its respective short-term cash requirements.

	As of December 31, 2009				
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**	**Expiration Date**	**Primary Purpose**
		Millions			
PSEG:					
5-year Credit Facility(A)	$ 1,000	$ 523(B)	$ 477	Dec 2012	Commercial Paper (CP) Support/Funding/Letters of Credit
Uncommitted Bilateral Agreement	N/A	26	N/A	N/A	Funding
Total PSEG	**$ 1,000**	**$ 549**	**$ 477**		
Power:					
5-year Credit Facility(A)	$ 1,600	$ 117(B)	$ 1,483	Dec 2012	Funding/Letters of Credit
2-year Credit Facility	350		350	July 2011	Funding
Bilateral Credit Facility	100	42(B)	58	March 2010	Funding/Letters of Credit
Total Power	**$ 2,050**	**$ 159**	**$ 1,891**		
PSE&G:					
5-year Credit Facility(A)	$ 600	$	$ 600	June 2012	CP Support/Funding/Letters of Credit
Uncommitted Bilateral Agreement	N/A		N/A	N/A	Funding
Total PSE&G	**$ 600**	**$**	**$ 600**		
Total	**$ 3,650**		**$ 2,968**		

(A) In December 2011, facilities reduce by $47 million, $75 million, and $28 million for PSEG, Power and PSE&G, respectively.

(B) Includes amounts related to letters of credit outstanding.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of December 31, 2009 and 2008.

	December 31, 2009	December 31, 2008
		Fair

	Carrying Amount	Fair Value*	Carrying Amount	Value*
	Millions			
Long-Term Debt:				
PSEG (Parent)	$ (38)	$ (3)	$ 249	$ 250
Power Recourse Debt	3,121	3,473	2,903	2,800
Power Project Level, Non-Recourse Debt			280	280
PSE&G	3,571	3,807	3,523	3,569
Transition Funding (PSE&G)	1,276	1,449	1,454	1,658
Transition Funding II (PSE&G)	67	71	76	80
Energy Holdings:				
Senior Notes	127	134	505	474
Project Level, Non-Recourse Debt	42	42	48	48
Total	**$ 8,166**	**$ 8,973**	**$ 9,038**	**$ 9,159**

* Excludes unamortized discount.

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Note 14. Schedule of Consolidated Capital Stock and Other Securities

	Outstanding Shares	Redemption Price Per Share	As of December 31, Book Value 2009	2008
			Millions	
PSEG Common Stock (no par value)(A)				
Authorized 1,000,000,000 shares; (outstanding as of December 31, 2008, 506,017,898 shares)	**505,989,630**		**$ 4,200**	**$ 4,175**
PSE&G Cumulative Preferred Stock (B) without Mandatory Redemption (C) $100 par value series				
4.08%	146,221	$ 103.00	$ 15	$ 15
4.18%	116,958	$ 103.00	12	12
4.30%	149,478	$ 102.75	15	15
5.05%	104,002	$ 103.00	10	10
5.28%	117,864	$ 103.00	12	12
6.92%	160,711	$ 101.73	16	16
Total Preferred Stock without Mandatory Redemption	**795,234**		**$ 80**	**$ 80**

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) and the Employee Stock Purchase Plan (ESPP) in 2009 or 2008. Total authorized and unissued shares of common stock available for issuance through PSEG s DRASPP, ESPP and various employee benefit plans amounted to 7.0 million shares as of December 31, 2009.

(B) As of December 31, 2009, there was an aggregate of 6.7 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption. If dividends upon any shares of Preferred Stock are in arrears for four consecutive quarters, holders receive voting rights for the election of a majority of PSE&G s Board of Directors. Such voting rights continue until all accumulated and unpaid dividends thereon have been paid, whereupon all such voting rights cease. There are no arrearages in cumulative preferred stock and no voting rights for preferred shares currently exist. No preferred stock agreement contains any liquidation preferences in excess of par values or any deemed liquidation events.

(C) As of each of December 31, 2009 and 2008, the annual dividend requirement and the embedded dividend rate for PSE&G s Preferred Stock without Mandatory Redemption was $4 million and 5.03%, respectively.

Fair Value of Preferred Securities

The estimated fair value of PSE&G s Cumulative Preferred Stock was $66 million as of December 31, 2009 and 2008. The estimated fair value was determined using market quotations.

On February 16, 2010, PSE&G irrevocably called for redemption on March 22, 2010 all of its outstanding preferred stock. PSE&G deposited the redemption price and the accrued unpaid dividends to the redemption date, into Bank of New York Mellon shareholder services, terminating all rights of holders of the preferred stock except the right to receive the redemption price upon surrender of shares. As a result all of the outstanding equity in PSE&G is owned by PSEG.

Note 15. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through

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hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events.

Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Contracts that do not qualify for hedge accounting or normal purchases normal sales treatment are marked to market with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists. The financial effect of using such modeling techniques is not material to PSEG s or Power s financial statements.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps, futures and firm transmission right contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations and

- the price of fuel to meet its fuel purchase requirements.

These derivative transactions are designated and effective as cash flow hedges. As of December 31, 2009 and 2008, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with these hedges was as follows:

	December 31, 2009	December 31, 2008
	Millions	
Fair Value of Cash Flow Hedges	$ 286	$ 334
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 184	$ 178

The expiration date of the longest-dated cash flow hedge at Power is in 2011. Power s after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the 12 months ending December 31, 2010 and December 31, 2011 are $99 million and $85 million, respectively. Ineffectiveness associated with these hedges was less than $1 million at December 31, 2009.

Trading Derivatives

In general, the main purpose of Power s wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets we serve. Power does engage in some trading of electricity and energy-related products where such transactions are not associated with the output or fuel purchase requirements of our facilities. This trading consists mostly of energy supply contracts where we secure sales commitments with the intent to supply the energy services from purchases in the market rather than from our owned generation. Such trading activities represent approximately one percent of Power s gross margin.

Other Derivatives

Power enters into other contracts that are derivatives, but do not qualify for cash flow hedge accounting. Most of these contracts are used for fuel purchases for generation requirements and for electricity purchases for contractual sales obligations. Prior to June 2009, some of the derivative contracts were also used in Power s NDT Funds.

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Changes in fair market value of these contracts are recorded in earnings. The fair value of these contracts as of December 31, 2009 and 2008 was $8 million and $94 million, respectively.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed through the use of fixed and floating rate debt and interest rate derivatives.

Fair Value Hedges

In May and June 2009, we entered into three interest rate swaps to convert Power s $250 million of 5.00% Senior Notes due April 2014 and $300 million of 5.50% Senior Notes due December 2015 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the fair value changes in the underlying debt. As of December 31, 2009, the fair value of the underlying hedges was $(3) million.

In January 2010, we entered into a series of interest rate swaps for a total of $600 million designated as fair value hedges to convert $300 million of Power s $303 million of 5.32% Senior Notes due September 2016 and $300 million of Power s $600 million of 6.95% of Senior Notes due June 2012 into variable-rate debt.

Cash Flow Hedges

PSEG, Power, PSE&G and Energy Holdings use interest rate swaps and other derivatives, which are designated and effective as cash flow hedges to manage their exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of December 31, 2009, there was no hedge ineffectiveness associated with these hedges. The total fair value of these interest rate derivatives was less than $1 million and $(7) million as of December 31, 2009 and 2008, respectively. The Accumulated Other Comprehensive Loss related to interest rate derivatives designated as cash flow hedges was $(4) million and $(6) million as of December 31, 2009 and 2008, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments in the Consolidated Balance Sheets:

	As of December 31, 2009					
	Power				PSE&G	Consolidated
	Cash Flow Hedges Energy-Related Contracts	Non Hedges Energy-Related Contracts	Netting (A)	Total Power	Non Hedges Energy-Related Contracts	Total Derivatives (B)
Derivative Contracts						
Current Assets	$ 357	$ 1,083	$ (1,209)	$ 231	$ 1	$ 243
Noncurrent Assets	$ 321	$ 255	$ (458)	$ 118	$ 5	$ 123
Total Mark-to-Market Derivative Assets	**$ 678**	**$ 1,338**	**$ (1,667)**	**$ 349**	**$ 6**	**$ 366**
Derivative Contracts						
Current Liabilities	$ (219)	$ (1,124)	$ 1,142	$ (201)	$	$ (201)

Noncurrent Liabilities	$ (173)	$ (235)	$ 382	$ (26)	$	$ (40)
Total Mark-to-Market Derivative Assets (Liabilities)	**$ (392)**	**$ (1,359)**	**$ 1,524**	**$ (227)**	**$**	**$ (241)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 286**	**$ (21)**	**$ (143)**	**$ 122**	**$ 6**	**$ 125**
Other Noncurrent Assets	**$**	**$**	**$**	**$**	**$**	**$**

(A) Represents the netting of fair value balances with the same counterparty and the application of collateral. As of December 31, 2009 and 2008, net cash collateral received of $143 million and $112

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million, respectively, was netted against the corresponding net derivative contract positions. Of the $143 million as of December 31, 2009, cash collateral of $(114) million and $(109) million were netted against current assets and noncurrent assets, respectively, and cash collateral of $47 million and $33 million were netted against current liabilities and noncurrent liabilities, respectively.

(B) Includes PSEG parent company interest rate swap assets of $11 million and interest rate swap liability of $(14) million, designated as fair value hedges, recorded in Current Assets-Derivative Contracts and Noncurrent Liability-Derivative Contracts respectively.

The aggregate fair value of derivative contracts in a liability position as of December 31, 2009 that contain triggers for additional collateral was $535 million. This potential additional collateral is included in the $986 million discussed in Note 12. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the twelve months ended December 31, 2009:

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)
			Millions		
PSEG(A)					
Energy-Related Contracts	$ 657	Operating Revenue	$ 690	Operating Revenue	$ (22)
Interest Rate Swaps		Income from Equity Method Investments	(1)		
Energy-Related Contracts	(53)	Energy Costs	(96)		
Interest Rate Swaps	(4)	Interest Expense	(7)		
Total PSEG	**$ 600**		**$ 586**		**$ (22)**
PSEG Power					
Energy-Related Contracts	$ 657	Operating Revenue	$ 690	Operating Revenue	$ (22)
Energy-Related Contracts	(53)	Energy Costs	(96)		
Interest Rate Swaps		Interest Expense	(4)		
Total Power	**$ 604**		**$ 590**		**$ (22)**
PSE&G					
Interest Rate Swaps	$ (1)	Interest Expense	$ (2)		$
Total PSE&G	**$ (1)**		**$ (2)**		**$**
Energy Holdings					

Interest Rate Swaps	$	Income from Equity Method Investments	$	(1)	$
	$		**$**	**(1)**	**$**

(A) Includes amounts for PSEG parent.

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2008	**$ 292**	**$ 172**
Gain Recognized in AOCI (Effective Portion)	601	356
Less: Gain Reclassified into Income (Effective Portion)	(588)	(348)
Balance as of December 31, 2009	**$ 305**	**$ 180**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for twelve months ended December 31, 2009:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives Twelve Months Ended December 31, 2009
		Millions
PSEG and Power		
Energy-Related Contracts	Operating Revenues	$ 139
Energy-Related Contracts	Energy Costs	(164)
Interest Rate Swaps	Interest Expense	(3)
Derivatives in NDT Funds	Other Income	13
Total PSEG and Power		**$ (15)**

Power s derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of those contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges for the twelve months ended December 31, 2009 was to reduce interest expense by approximately $1 million.

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2009:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
Natural Gas	Dth	842		613	229
Electricity	MWh	194		190	
Capacity	MW days	1		1	
FTRs	MWh	23		23	
Emissions Allowances	Tons	1		1	
Oil	Barrels				
Renewable Energy Credits	MWh	1		1	
Interest Rate Swaps	US Dollars	550	550		

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Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we 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 allow for the netting of positive and negative exposures associated with a single counterparty.

In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power s financial condition, results of operations or net cash flows. As of December 31, 2009, 99% of the credit exposure (MTM plus net receivables and payables, less cash collateral) for Power s operations was with investment grade counterparties.

The following table provides information on Power s credit risk from others, net of collateral, as of December 31, 2009. 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 quality of the company s credit risk by credit rating of the counterparties.

Rating	**Current Exposure**	**Securities held as Collateral**	**Net Exposure**	**Number of Counterparties >10%**	**Net Exposure of Counterparties >10%**
		Millions			Millions
Investment Grade External Rating	$ 1,340	$ 111	$ 1,280	2	$ 773(A)
Non-Investment Grade External Rating	4	3	1		
Investment Grade No External Rating	29		29		
Non-Investment Grade No External Rating	12	22	8		
Total	**$ 1,385**	**$ 136**	**$ 1,318**	**2**	**$ 773**

(A) Includes net exposure of $636 million with PSE&G. The remaining net exposure of $137 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

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 cash collateral than the outstanding exposure, in which case there would not be exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of December 31, 2009, Power had 195 active counterparties.

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Note 16. Fair Value Measurements

PSEG, Power and PSE&G adopted accounting guidance for Fair Value Measurements for financial assets and liabilities effective January 1, 2008, and for nonrecurring fair value measurements of non-financial assets and liabilities effective January 1, 2009. The fair value measurements guidance defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity s own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1 measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2 measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3 measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity s own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument s level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. These consist mainly of various financial transmission rights, other longer term capacity and transportation contracts and certain commingled securities.

In addition to establishing a measurement framework, the fair value measurement guidance nullified the prior guidance which did not allow an entity to recognize an unrealized gain or loss at the inception of a derivative instrument unless the fair value of that instrument was obtained from a quoted market price in an active market or was otherwise evidenced by comparison to other observable current market transactions or based on a valuation technique incorporating observable market data. Under prior guidance, Power had a deferred inception loss of $34 million, pre-tax, as of December 31, 2007 related to a five-year capacity contract at its generation facilities, which was being amortized at $11 million per year through 2010. In accordance with the provisions of Fair Value Measurements, Power recorded a cumulative effect adjustment of $21 million after-tax to January 1, 2008 Retained Earnings in its Consolidated Balance Sheet associated with the implementation of fair value measurements guidance.

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The following tables present information about PSEG s, Power s and PSE&G s respective assets and (liabilities) measured at fair value on a recurring basis at December 31, 2009 and December 31, 2008, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

	Recurring Fair Value Measurements as of December 31, 2009				
Description	Total	Cash Collateral Netting(E)	Quoted Market Prices of Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 355	$ (223)	$	$ 415	$ 163
Interest Rate Swaps(B)	$ 11	$	$	$ 11	$
NDT Funds(C)					
Equity Securities	$ 650	$	$ 650	$	$
Debt Securities-Government Obligations	$ 297	$	$	$ 297	$
Debt Securities-Other	$ 216	$	$	$ 216	$
Other Securities	$ 36	$	$	$ 27	$ 9
Rabbi Trusts(C)	$ 149	$	$ 14	$ 121	$ 14
Other Long-Term Investments(D)	$ 2	$	$ 2	$	$
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (227)	$ 80	$	$ (267)	$ (40)
Interest Rate Swaps(B)	$ (14)	$	$	$ (14)	$
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 349	$ (223)	$	$ 415	$ 157
NDT Funds(C)					
Equity Securities	$ 650	$	$ 650	$	$
Debt Securities-Government Obligations	$ 297	$	$	$ 297	$
Debt Securities-Other	$ 216	$	$	$ 216	$
Other Securities	$ 36	$	$	$ 27	$ 9
Rabbi Trusts Mutual Funds(C)	$ 30	$	$ 3	$ 24	$ 3
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (227)	$ 80	$	$ (267)	$ (40)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 6	$	$	$	$ 6
Rabbi Trusts(C)	$ 51	$	$ 5	$ 41	$ 5

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Description	Total	Cash Collateral Netting (E)	Quoted Market Prices of Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Recurring Fair Value Measurements as of December 31, 2008				
					Millions
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 399	$ (154)	$	$ 439	$ 114*
NDT Funds(C)					
Equity Securities	$ 413	$	$ 412	$ 1	$
Debt Securities-Government Obligations	$ 195	$	$	$ 195	$
Debt Securities-Other	$ 290	$	$	$ 285	$ 5
Other Securities	$ 72	$	$ 1	$ 35	$ 36
Rabbi Trusts(C)	$ 133	$	$ 9	$ 110	$ 14
Other Long-Term Investments(D)	$ 1	$	$ 1	$	$
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (510)	$ 42	$	$ (470)	$ (82)*
Interest Rate Swaps(B)	$ (10)	$	$	$ (10)	$
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 408	$ (154)	$	$ 450	$ 112*
NDT Funds(C)					
Equity Securities	$ 413	$	$ 412	$ 1	$
Debt Securities-Government Obligations	$ 195	$	$	$ 195	$
Debt Securities-Other	$ 290	$	$	$ 285	$ 5
Other Securities	$ 72	$	$ 1	$ 35	$ 36
Rabbi Trusts Mutual Funds(C)	$ 27	$	$ 2	$ 22	$ 3
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (454)	$ 42	$	$ (480)	$ (16)*
Interest Rate Swaps	$ (9)	$	$	$ (9)	$
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 2	$	$	$	$ 2
Rabbi Trusts(C)	$ 46	$	$ 3	$ 38	$ 5
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (66)	$	$	$	$ (66)
Interest Rate Swaps(B)	$ (1)	$	$	$ (1)	$

*

The amounts shown in energy-related contract assets and liabilities in the table above have been corrected from such amounts shown in our 2008 Form 10-K to reflect a $22 million increase in the Level 2 net liability and a corresponding increase in the Level 3 net asset. The amounts for Power have also been retrospectively adjusted to include amounts related to PSEG Texas.

(A) Whenever possible, fair values for energy-related contracts are obtained from quoted market sources in active markets. When this pricing is unavailable, contracts are valued using broker or dealer quotes or auction prices (primarily Level 2).

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For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information is available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable (primarily Level 3).

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Funds maintain investments in various equity and fixed income securities classified as available for sale. These securities are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. All fair value measurements for the fund securities are provided by the trustees of these funds. Most equity securities are priced utilizing the principal market close price or in some cases midpoint, bid or ask price (primarily Level 1). Fixed income securities are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2). Short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2). Certain commingled cash equivalents included in temporary investment funds are measured with significant unobservable inputs and internal assumptions (primarily Level 3). The Rabbi Trust mutual funds are mainly invested in a US Bond Index fund, an S&P 500 Index fund and a commingled temporary investment fund. The equity index fund is valued based on quoted prices in an active market (Level 1) while the bond index fund is valued using recent exchange prices or a quoted bid (Level 2).

(D) Other long-term investments consist of equity securities and are valued using a market based approach based on quoted market prices.

(E) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ending December 31, 2009

		Total Gains or (Losses) Realized/Unrealized			
Description	**Balance as of January 1, 2009**	**Included in Income(A)**	**Included in Regulatory Assets/ Liabilities(B)**	**Purchases, (Sales) and Settlements**	**Balance as of December 31, 2009**
			Millions		
PSEG					
Net Derivative Assets	$ 32	$ 134	$ 70	$ (113)	$ 123
NDT Funds	$ 41	$	$	$ (32)	$ 9
Rabbi Trust Funds	$ 14	$	$	$	$ 14
Power					
Net Derivative Assets	$ 96	$ 134	$	$ (113)	$ 117
NDT Funds	$ 41	$	$	$ (32)	$ 9

Rabbi Trust Funds	$	3	$		$		$		$	3
PSE&G										
Net Derivative Liabilities	$	(64)	$		$	70	$		$	6
Rabbi Trust Funds	$	5	$		$		$		$	5

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ending December 31, 2008

Description	Balance as of January 1, 2008	Total Gains or (Losses) Realized/Unrealized Included in Income(C)	Included in Regulatory Assets/ Liabilities(B)	Purchases, (Sales) and Settlements	Balance as of December 31, 2008
			Millions		
PSEG					
Net Derivative Assets	$ (9)	$ 209	$ (15)	$ (153)	$ 32
NDT Funds	$ 27	$ (4)	$	$ 18	$ 41
Rabbi Trust Funds	$ 16	$	$	$ (2)	$ 14
Power					
Net Derivative Assets	$ 40	$ 209	$	$ (153)	$ 96
NDT Funds	$ 27	$ (4)	$	$ 18	$ 41
Rabbi Trust Funds	$ 3	$	$	$	$ 3
PSE&G					
Net Derivative Liabilities	$ (49)	$	$ (15)	$	$ (64)
Rabbi Trust Funds	$ 6	$	$	$ (1)	$ 5

(A) PSEG s and Power s gains and losses are mainly attributable to changes in net derivative assets and liabilities of which $155 million is included in Operating Revenues and $ (21) million is included in OCI. Of the $155 million in Operating Revenues, $42 million is unrealized and $113 million is realized.

(B) Mainly includes losses on PSE&G s derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset and are expected to be recovered from PSE&G s customers.

(C) PSEG s and Power s gains and losses are mainly attributable to changes in net derivative assets and liabilities of which $207 million is included in Operating Revenues and $2 million is included in OCI. Of the $207 million in Operating Revenues, $110 million is unrealized and $97 million is realized.

As of December 31, 2009, PSEG carried approximately $1.5 billion of net assets that are measured at fair value on a recurring basis, of which approximately $146 million were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy. These Level 3 net assets represent less than 1% of PSEG s total assets. During the year, approximately $15 million of net derivative liabilities were transferred from Level 3 to Level 2 due to more observable pricing in the Texas market.

As of December 31, 2008, PSEG carried approximately $1 billion of net assets that are measured at fair value on a recurring basis, of which approximately $87 million were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy. These Level 3 net assets represent less than 1% of PSEG s total assets and there were no significant transfers in or out of Level 3 during the year ending December 31, 2008.

Non-recurring Fair Value Measurements

As discussed in Note 4. Discontinued Operations, Dispositions and Impairments, Energy Holdings sold a 10.1% interest in its GWF Energy investment during the second quarter of 2009 and recorded an after-tax impairment charge of $3 million on the entire investment prior to the sale. The remaining investment of $63 million is carried as a nonrecurring fair value measurement as of June 30, 2009. This investment is considered a Level 3 within the fair value hierarchy based on the use of unobservable inputs.

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During the fourth quarter of 2009, Energy Holdings recorded an after-tax impairment charge of $3 million on its investment in Venezuela. The remaining investment of $3 million is carried as a nonrecurring fair value measurement as of December 31, 2009. The investment is considered a Level 3 within the fair value hierarchy based on the use of unobservable inputs.

The table of fair value of debt is included in Note 13. Schedule of Consolidated Debt.

Note 17. Stock Based Compensation

As approved at the Annual Meeting of Stockholders in 2004, PSEG s 2004 Long-Term Incentive Plan (LTIP) replaced the prior 1989 LTIP and 2001 LTIP. The 2004 LTIP is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIPs are non-qualified options to purchase shares of PSEG s common stock, restricted stock awards, restricted stock unit awards and performance unit awards.

The 2004 LTIP currently provides for the issuance of equity awards with respect to approximately 26 million shares of common stock. As of December 31, 2009, there were approximately 18 million shares available for future awards under the 2004 LTIP.

Stock Options

Under the 2004 LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the Organization and Compensation Committee of PSEG s Board of Directors, the plan s administrative committee (Committee). Option awards are granted with an exercise price equal to the market price of PSEG s common stock at the grant date. The options generally vest based on three to five years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the Committee (but not prior to one year or longer than 10 years from the date of grant) and are subject to such other terms and conditions as the Committee determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the Committee, by delivering previously acquired shares of PSEG common stock.

Restricted Stock

Under the 2004 LTIP, PSEG has granted restricted stock awards to officers and other key employees. These shares are subject to risk of forfeiture until vested by continued employment. Restricted stock generally vests annually over three or four years, but is considered outstanding at the time of grant, as the recipients are entitled to dividends and voting rights. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Restricted Stock Units

Under the 2004 LTIP, PSEG has granted restricted stock unit awards to officers and certain other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. The restricted stock units generally vest annually over four years and distributions are made in shares of common stock. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Performance Share Units

Under the 2004 LTIP, performance share units were granted to certain key executives, which provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. The payout varies from 0% to 200% of the number of performance share units granted

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

depending on PSEG s performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents in an amount equal to dividends paid on PSEG common stock up until the shares are distributed. Vesting may be accelerated upon certain events such as change-in-control, retirement, death or disability.

Stock-Based Compensation

All outstanding unvested stock options are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock over the vesting period based on the grant date fair market value of the shares. PSEG will continue to recognize compensation expense over the vesting term.

PSEG recognized compensation expense for performance share units based on the grant date fair value of PSEG common stock. The accrual of compensation cost was based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. The current accrual is estimated at 100% of the original grant. The accrual is adjusted for subsequent changes in the estimated or actual outcome.

	2009	2008	2007
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 27	$ 21	$ 22
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 11	$ 8	$ 9

There was $3 million, $3 million and $18 million of excess tax benefits included as a financing cash inflow in the Consolidated Statements of Cash Flow for the years ended December 31, 2009, 2008 and 2007, respectively.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

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Changes in stock options for 2009 are summarized as follows:

	2009	
	Options	Weighted Average Exercise Price
Beginning of Year	3,784,834	$ 30.67
Granted	929,800	33.22
Exercised	(483,134)	23.41
Cancelled	(89,450)	31.94
End of Year	**4,142,050**	**$ 32.06**
Exercisable at End of Year	1,750,712	$ 29.61

Options	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding at December 31, 2009	7.7	$ 4,931,854
Exercisable at December 31, 2009	6.0	$ 6,364,975

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The following weighted average assumptions were used for grants in 2009, 2008 and 2007:

			2007	
	2009	2008	January - June	December
Expected Volatility	29.00%	29.30%	24.87%	24.60%
Risk-Free Interest Rate	2.84%	1.72%	4.72%	3.78%
Expected Life (Years)	6.25	6.25	6.25	6.25
Weighted Average Dividend Yield	4.00%	4.30%	3.46%	2.40%

The risk-free rate assumption is based upon U.S. Treasury yields in effect at the time of grant. The expected volatility assumption is based on the historical volatility of daily stock prices. The expected life of all options is calculated using the simplified method which assumes options are exercised midway between the vesting date and the contractual term of the option. PSEG will continue to use the simplified method until there is adequate historical experience for option exercises.

The intrinsic value of options is the difference between the current market price and the exercise price. Activity for options exercised is shown below:

	2009	2008	2007
		Millions	
Total Intrinsic Value of Options Exercised	$ 4	$ 4	$ 43
Cash Received from Options Exercised	$ 11	$ 5	$ 49
Tax Benefit Realized from Options Exercised	$ 3	$ 3	$ 18

Approximately one million options vested during the years ended December 31, 2009, 2008 and 2007. The weighted average fair value per share for options vested during the years ended December 31, 2009, 2008 and 2007 was $35.07, $35.40 and $24.93, respectively.

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As of December 31, 2009, there was approximately $14 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted average period of 1.37 years.

Restricted Stock Information

Changes in restricted stock for the year ended December 31, 2009 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2009	308,284	$ 36.89		
Granted	8,800	30.18		
Vested	(75,674)	38.61		
Cancelled	(4,852)	40.05		
Outstanding at December 31, 2009	**236,558**	**$ 36.03**	**1.12**	**$ 7,865,554**

The weighted average grant date fair value per share was $30.18 and $37.18 for restricted stock awards granted during 2009 and 2007, respectively. There were no restricted stock awards granted in 2008.

The total intrinsic value of restricted stock vested during the years ended December 31, 2009 and 2008 was $3 million and $2 million, respectively.

As of December 31, 2009, there was approximately $4 million of unrecognized compensation cost-related to restricted stock, which is expected to be recognized over a weighted average period of 1.15 years.

Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2009 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2009	428,911	$ 41.76		
Granted	328,725	30.19		
Vested	(86,714)	45.67		
Cancelled	(20,733)	32.35		
Outstanding at December 31, 2009	**650,189**	**$ 35.69**	**3.06**	**$ 21,618,784**

The total intrinsic value of restricted stock units vested during the year ended December 31, 2009 was $3 million.

As of December 31, 2009, there was approximately $15 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of 1.46 years. 27,826 dividend equivalents accrued on the restricted stock units during the year.

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Performance Share Units Information

Performance Share Unit information for 2009 is detailed below:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2009	768,620	$ 37.05		
Granted	236,400	36.41		
Vested	(232,390)	43.81		
Cancelled	(53,166)	36.55		
Outstanding at December 31, 2009	**719,464**	**$ 34.70**	**2.02**	**$ 23,922,178**

As of December 31, 2009, there was approximately $17 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of 1.29 years. 31,098 dividend equivalents accrued on the performance share units during the year.

Outside Directors

Beginning in 2007, a Director Compensation plan was approved. Annually, on May 1, each non-employee board member is awarded stock units based on amount of annual compensation to be paid and the May 1 closing price of PSEG common stock. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the board.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the Stock Plan for each of the years ended December 31, 2009, 2008 and 2007 was approximately $1 million.

Employee Stock Purchase Plan

PSEG maintains an employee stock purchase plan for all eligible employees of PSEG and its subsidiaries. Under the plan, shares of PSEG common stock may be purchased at 95% of the fair market value through payroll deductions. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. During the years ended December 31, 2009, 2008 and 2007, employees purchased 173,350, 109,921 and 88,656 shares at an average price of $29.20, $38.35 and $39.64 per share, respectively. As of December 31, 2009, 3.6 million shares were available for future issuance under this plan.

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Note 18. Other Income and Deductions

Other Income	Power	PSE&G	Other(A)	Consolidated Total
			Millions	
For the Year Ended December 31, 2009:				
NDT Fund Gains	$ 183	$	$	$ 183
NDT Interest, Dividend and Other Income	44			44
Other Interest and Dividend Income	6	1	2	9
Other	1	7	3	11
Total Other Income	**$ 234**	**$ 8**	**$ 5**	**$ 247**
For the Year Ended December 31, 2008:				
NDT Fund Gains	$ 354	$	$	$ 354
NDT Interest, Dividend and Other Income	53			53
Other Interest and Dividend Income	7	5	6	18
Other	2	7	2	11
Total Other Income	**$ 416**	**$ 12**	**$ 8**	**$ 436**
For the Year Ended December 31, 2007:				
NDT Fund Gains	$ 164	$	$	$ 164
NDT Interest, Dividend and Other Income	50			50
Other Interest and Dividend Income	24	10	2	36
Other	4	6	19	29
Total Other Income	**$ 242**	**$ 16**	**$ 21**	**$ 279**

Other Deductions	Power	PSE&G	Other(A)	Consolidated Total
			Millions	
For the Year Ended December 31, 2009:				
NDT Fund Losses and Expenses	$ 117	$	$	$ 117
Other	18	3	23	44
Total Other Deductions	**$ 135**	**$ 3**	**$ 23**	**$ 161**
For the Year Ended December 31, 2008:				
NDT Fund Losses and Expenses	$ 302	$	$	$ 302
Other	14	4	16	34

Total Other Deductions	**$ 316**	**$ 4**	**$ 16**	**$ 336**
For the Year Ended December 31, 2007:				
NDT Fund Losses and Expenses	$ 94	$	$	$ 94
Loss on Early Retirement of Debt			47	47
Other	3	4	40	47
Total Other Deductions	**$ 97**	**$ 4**	**$ 87**	**$ 188**

(A) Other primarily consists of activity at PSEG (parent company), Energy Holdings and Services and intercompany eliminations.

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Note 19. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	2009	2008	2007
		Millions	
Net Income	$ 1,592	$ 1,188	$ 1,335
Income from Discontinued Operations, including Gain on Disposal, net of tax benefit		205	10
Income from Continuing Operations	1,592	983	1,325
Preferred Dividends	(4)	(4)	(4)
Income from Continuing Operations, excluding Preferred Dividends	$ 1,596	$ 987	$ 1,329
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 562	$ 1,430	$ 705
State	257	123	156
Total Current	819	1,553	861
Deferred Expense:			
Federal	178	(768)	150
State	44	144	57
Total Deferred	222	(624)	207
Foreign			
Investment Tax Credit	3	(3)	(4)
Total Income Taxes	**$ 1,044**	**$ 926**	**$ 1,064**
Pre-Tax Income	$ 2,640	$ 1,913	$ 2,393
Tax Computed at Statutory Rate @ 35%	$ 924	$ 669	$ 837
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	201	169	144
Foreign Operations			82
Uncertain Tax Positions	(73)	135	29
Other	(8)	(47)	(28)
Sub-Total	120	257	227

Total Income Tax Provision	**$ 1,044**	**$ 926**	**$ 1,064**
Effective Income Tax Rate	39.5%	48.4%	44.5%

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The following is an analysis of deferred income taxes for PSEG:

	2009	2008
Deferred Income Taxes	Millions	
Assets:		
Current (net)	$ 52	$ 52
Noncurrent:		
Unrecovered Investment Tax Credit	14	14
OCI	28	44
Cumulative Effect of a Change in Accounting Principle	11	11
New Jersey Corporate Business Tax	52	81
OPEB	269	242
Cost of Removal	51	51
Nuclear Decommissioning		17
Related to Foreign Operations		6
Development Fees	1	8
Contractual Liabilities & Environmental Costs	35	35
MTC	17	17
Related to Uncertain Tax Positions	507	1,017
Other	15	11
Total Noncurrent	1,000	1,554
Total Assets	$ 1,052	$ 1,606
Liabilities:		
Current (net)	$	$
Noncurrent:		
Plant-Related Items	2,133	1,878
Nuclear Decommissioning	113	
Securitization	771	888
Leasing Activities	1,246	1,883
Partnership Activity	63	87
Repair Allowance Deferred Carrying Charge	13	16
Conservation Costs	26	20
Energy Clause Recoveries	72	37
Pension Costs	124	74
Related to Foreign Operations	7	
Asset Retirement Obligations	325	325
Taxes Recoverable Through Future Rate (net)	159	164
Other	35	(1)
Total Noncurrent Liabilities	5,087	5,371

Total Liabilities	$ 5,087	$ 5,371
Summary of Accumulated Deferred Income Taxes:		
Net Current Assets	$ 52	$ 52
Net Noncurrent Liability	4,087	3,817
	4,035	3,765
ITC	52	48
Current Portion of Deferred Income Taxes Transferred	52	52
Total Deferred Income Taxes and ITC	**$ 4,139**	**$ 3,865**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	2009	2008	2007
		Millions	
Net Income	$ 1,189	$ 1,115	$ 992
Loss from Discontinued Operations, net of tax benefit			(8)
Income from Continuing Operations	$ 1,189	$ 1,115	$ 1,000
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 418	$ 467	$ 447
State	144	130	121
Total Current	562	597	568
Deferred Expense:			
Federal	177	86	86
State	30	16	22
Total Deferred	207	102	108
Total Income Taxes	**$ 769**	**$ 699**	**$ 676**
Pre-Tax Income	$ 1,958	$ 1,814	$ 1,676
Tax Computed at Statutory Rate @ 35%	$ 685	$ 635	$ 587
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	113	95	93
Manufacturing Deduction	(7)	(22)	(13)
Nuclear Decommissioning Trust	7	(10)	6
Uncertain Tax Positions	(26)	4	2
Other	(3)	(3)	1
Sub-Total	84	64	89
Total Income Tax Provision	**$ 769**	**$ 699**	**$ 676**
Effective Income Tax Rate	39.3%	38.5%	40.3%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

Deferred Income Taxes	**2009**	**2008**
Assets:	**Millions**	
Noncurrent:		
Cumulative Effect of a Change in Accounting Principle	$ 11	$ 11
New Jersey Corporate Business Tax	69	76
Pension Costs	48	63
Cost of Removal	51	51
Nuclear Decommissioning		17
Contractual Liabilities & Environmental Costs	35	35
Related to Uncertain Tax positions		9
Other	15	43
Total Noncurrent	229	305
Total Assets	$ 229	$ 305
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 349	$ 292
OCI	10	5
Nuclear Decommissioning	113	
Partnership Activity	34	46
Asset Retirement Obligations	325	325
Related to Uncertain Tax Positions	37	
Total Noncurrent	868	668
Total Liabilities	$ 868	$ 668
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Liability	$ 639	$ 363
ITC	5	5
Total Deferred Income Taxes and ITC	**$ 644**	**$ 368**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	2009	2008	2007
		Millions	
Net Income	321	360	376
Preferred Dividends	(4)	(4)	(4)
Income from Continuing Operations, excluding Preferred Dividends	$ 325	$ 364	$ 380
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 7	$ 74	$ 214
State	22	38	67
Total Current	29	112	281
Deferred Expense:			
Federal	158	92	(22)
State	38	26	1
Total Current	196	118	(21)
Investment Tax Credit	1	(2)	(3)
Total Income Taxes	$ 226	$ 228	$ 257
Pre-Tax Income	$ 551	$ 592	$ 637
Tax Computed at Statutory Rate @ 35%	$ 193	$ 207	$ 223
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	39	42	44
Uncertain Tax Positions	(3)	(18)	(3)
Other	(3)	(3)	(7)
Sub-Total	33	21	34
Total Income Tax Provision	**$ 226**	**$ 228**	**$ 257**
Effective Income Tax Rate	41.0%	38.5%	40.3%

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The following is an analysis of deferred income taxes for PSE&G:

	2009	2008
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 52	$ 52
Noncurrent:		
Unrecovered ITC	14	14
New Jersey Corporate Business Tax	57	98
OPEB	263	237
MTC	17	17
Total Noncurrent	$ 351	$ 366
Total Assets	$ 403	$ 418
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 1,780	$ 1,586
OCI	3	1
Securitization	771	888
Repair Allowance Deferred Carrying Charge	13	16
Conservation Costs	26	20
Energy Clause Recoveries	72	37
Pension Costs	141	105
Related to Uncertain Tax Positions	23	18
Taxes Recoverable Through Future Rate(net)	159	164
Other	33	25
Total Noncurrent Liabilities	3,021	2,860
Total Liabilities	$ 3,021	$ 2,860
Summary of Accumulated Deferred Income Taxes:		
Net Current Assets	$ 52	$ 52
Net NonCurrent Liability	2,670	2,494
	2,618	2,442
ITC	40	39
Current Portion of Deferred Income Taxes Transferred	52	52
Total Deferred Income Taxes and ITC	**$ 2,710**	**$ 2,533**

Each of PSEG, Power and PSE&G provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from PSE&G s customers in the future. Accordingly, an offsetting Regulatory Asset was established. As of December 31, 2009, PSE&G had a Regulatory Asset of $409 million, representing the tax costs expected to be recovered through rates based upon established regulatory practices, which permit recovery of current taxes payable. This amount was determined using the enacted federal income tax rate of 35% and state income tax rate of 9%.

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PSEG and its subsidiaries adopted new guidance effective January 1, 2007, which prescribes a model for how a company should recognize, measure, present and disclose in its financial statements uncertain tax positions that it has taken or expects to take on a tax return. PSEG recorded the following amounts related to its uncertain tax positions, which was primarily comprised of amounts recorded for Power, PSE&G and Energy Holdings:

2009	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits at January 1, 2009	$ 1,403	$ 30	$ 27	$ 1,323
Increases as a Result of Positions Taken in a Prior Period	37	1	8	26
Decreases as a Result of Positions Taken in a Prior Period	(580)	(39)	(9)	(530)
Increases as a Result of Positions Taken during the Current Period	15	1	10	4
Decreases as a Result of Positions Taken during the Current Period	(19)	(18)	(1)	
Decreases as a Result of Settlements with Taxing Authorities	(5)	(5)		
Decreases due to Lapses of Applicable Statute of Limitations	(15)	(12)		(3)
Total Amount of Unrecognized Tax Benefits at December 31, 2009	$ 836	$ (42)	$ 35	$ 820
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(508)	37	22	(551)
Regulatory Asset Unrecognized Tax Benefits	(55)		(55)	
Total Amount of Unrecognized Tax Benefits that if Recognized, Would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 273**	**$ (5)**	**$ 2**	**$ 269**

2008	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits at January 1, 2008	$ 556	$ 31	$ 78	$ 449
Increases as a Result of Positions Taken in a Prior Period	903	6	3	869
Decreases as a Result of Positions Taken in a Prior Period	(124)	(9)	(63)	(52)
Increases as a Result of Positions Taken during the Current Period	90	2	10	78
Decreases as a Result of Positions Taken during the Current Period	(2)		(1)	(1)
Decreases as a Result of Settlements with Taxing Authorities	(20)			(20)
Decreases due to Lapses of Applicable Statute of Limitations				
Total Amount of Unrecognized Tax Benefits at December 31, 2008	$ 1,403	$ 30	$ 27	$ 1,323
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(1,017)	(10)	18	(1,009)

Regulatory Asset Unrecognized Tax Benefits	(39)		(39)	
Total Amount of Unrecognized Tax Benefits that if Recognized, Would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 347**	**$ 20**	**$ 6**	**$ 314**

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2007	PSEG	Power	PSE&G	Energy Holdings
			Millions	
Total Amount of Unrecognized Tax Benefits at January 1, 2007	$ 485	$ 31	$ 55	$ 398
Increases as a Result of Positions Taken in a Prior Period	81	3	14	64
Decreases as a Result of Positions Taken in a Prior Period	(35)	(8)		(27)
Increases as a Result of Positions Taken during the Current Period	41	5	10	26
Decreases as a Result of Positions Taken during the Current Period	(16)		(1)	(12)
Decreases as a Result of Settlements with Taxing Authorities				
Decreases due to Lapses of Applicable Statute of Limitations				
Total Amount of Unrecognized Tax Benefits at December 31, 2007	$ 556	$ 31	$ 78	$ 449
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(286)	(14)	(14)	(260)
Regulatory Asset Unrecognized Tax Benefits	(38)		(38)	
Total Amount of Unrecognized Tax Benefits that if Recognized, Would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 232**	**$ 17**	**$ 26**	**$ 189**

On June 26, 2009, September 15, 2008 and December 17, 2007, PSEG made tax deposits with the IRS in the amount of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments (see Note 12. Commitments and Contingent Liabilities). The $320 million of deposits are fully refundable and are recorded to the Long-Term Accrued Taxes in PSEG s Consolidated Balance Sheets, but are not reflected in the amounts shown above.

PSEG and its subsidiaries include all accrued interest and penalties related to unrecognized tax benefits required to be recorded, as income tax expense. PSEG s interest and penalties on Unrecognized Tax Benefits as of December 31, 2009, 2008 and 2007 was $354 million, $349 million and $142 million, respectively, including $(2) million, $10 million and $7 million at Power, $(22) million, $(22) million and $13 million at PSE&G and $370 million, $354 million and $122 million at Energy Holdings.

As a result of a change in accounting method for the capitalization of indirect costs, PSEG reduced the net amount of its unrecognized tax benefits (including interest) by $90 million, approximately $41 million of which related to PSE&G. It is reasonably possible that PSE&G s claim related to this matter will be settled with the IRS in the next 12 months, resulting in an increase in the unrecognized tax benefits.

It is reasonably possible that total unrecognized tax benefits at PSEG will decrease by $160 million within the next 12 months due to either agreement with various taxing authorities upon audit or the expiration of the Statute of Limitations. This amount includes a $3 million increase for Power, a $10 million decrease for PSE&G, a $26 million decrease for Services, a $132 million decrease for Energy Holdings and a $5 million increase for PSEG parent.

It is reasonably possible that unrecognized tax benefits associated with the leasing tax issue discussed in Note 12. Commitments and Contingent Liabilities, will change significantly. This change could be triggered by a settlement with the IRS or developments in other litigated cases. Based upon these developments, unrecognized tax benefits could increase by as much as $275 million or decrease by as much as $674 million. It is not possible to predict the magnitude, timing or direction of any such change.

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Description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	Power	PSE&G
United States			
Federal	2001-2008	2001-2008	2001-2008
New Jersey	2005-2008	N/A	2005-2008
Pennsylvania	2004-2008	N/A	2004-2008
Connecticut	2003-2008	N/A	N/A
Texas	2008	N/A	N/A
California	2003-2008	N/A	N/A
Indiana	2003-2008	N/A	N/A
Ohio	2004-2008	N/A	N/A
New York	2004-2008	2004-2008	N/A
Foreign			
Chile	2004-2008	N/A	N/A
Peru	2002-2008	N/A	N/A

Note 20. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG s stock compensation plans and upon payment of performance share units or restricted stock units. The following table shows the effect of these stock options, restricted stock awards, performance share units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	For the Years Ended December 31,					
	2009		2008		2007	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
Earnings (Millions)						
Continuing Operations	$ 1,592	$ 1,592	$ 983	$ 983	$ 1,325	$ 1,325
Discontinued Operations			205	205	10	10
Net Income	**$ 1,592**	**$ 1,592**	**$ 1,188**	**$ 1,188**	**$ 1,335**	**$ 1,335**
EPS Denominator (Thousands):						
Weighted Average Common Shares Outstanding	505,986	505,986	507,693	507,693	507,560	507,560
Effect of Stock Options		183		341		678
Effect of Stock Performance Share Units		786		322		560
Effect of Restricted Stock						12

Effect of Restricted Stock Units				109				71				3
Total Shares		**505,986**		**507,064**		**507,693**		**508,427**		**507,560**		**508,813**
EPS:												
Continuing Operations	$	3.15	$	3.14	$	1.94	$	1.93	$	2.61	$	2.60
Discontinued Operations						0.40		0.41		0.02		0.02
Net Income	**$**	**3.15**	**$**	**3.14**	**$**	**2.34**	**$**	**2.34**	**$**	**2.63**	**$**	**2.62**

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There were approximately 1.6 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the year ended December 31, 2009. No other stock options had an antidilutive effect for the years ended December 31, 2009, 2008 or 2007.

Dividends

Dividend payments on common stock for the year ended December 31, 2009 were $1.33 per share and totaled $673 million. Dividend payments on common stock for the year ended December 31, 2008 were $1.29 per share and totaled $655 million.

On February 16, 2010, PSEG s Board of Directors approved a $0.01 increase in its quarterly common stock dividend, from $0.3325 to $0.3425 per share for the first quarter of 2010.

Note 21. Financial Information by Business Segment

Basis of Organization

PSEG s operating segments are Power, PSE&G and Energy Holdings. The operating segments were determined by management in accordance with GAAP Disclosures about Segments of an Enterprise and Related Information. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how it allocates resources to each business.

On October 1, 2009, the Texas generation facilities were transferred from Energy Holdings to Power. As a result, the earnings and assets and liabilities related to the Texas facilities are presented as if the transfer occurred at the beginning of the year, and prior years have been retrospectively adjusted to furnish comparative information. See Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into trading contracts for energy, capacity, financial transmission rights, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Energy Holdings

Energy Holdings earns revenues from its portfolio of passive investments primarily consisting of leveraged leases. The lease investments are domestic and international; however, revenues from all international investments are denominated in U.S. dollars. Gains and losses on sales of these investments are typically recognized in revenues. Energy Holdings also has equity method generation projects. Earnings from these projects are presented below Operating Income.

Other

Other activities include amounts applicable to PSEG (parent corporation), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case

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of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 22. Related-Party Transactions. The net losses primarily relate to financing and certain administrative and general cost.

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2009:					
Total Operating Revenues	$ 7,143	$ 8,243	$ 221	$ (3,201)	$ 12,406
Depreciation and Amortization	203	608	11	16	838
Operating Income	2,086	858	163	14	3,121
Income from Equity Method Investments			39		39
Interest Income	6	1	5	(6)	6
Interest Expense	167	312	37	11	527
Income before Income Taxes	1,958	551	117	10	2,636
Income Tax Expense	769	226	45	4	1,044
Net Income	1,189	325	72	6	1,592
Segment Earnings	1,189	321	72	10	1,592
Gross Additions to Long-Lived Assets	$ 869	$ 855	$ 62	$ 8	$ 1,794
As of December 31, 2009:					
Total Assets	$ 10,333	$ 16,533	$ 2,605	$ (741)	$ 28,730
Investments in Equity Method Subsidiaries	$ 36	$	$ 176		$ 212

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2008:					
Total Operating Revenues	$ 8,483	$ 9,038	$ (368)	$ (3,831)	$ 13,322
Depreciation and Amortization	181	583	12	16	792
Operating Income (Loss)	2,125	909	(437)	16	2,613
Income from Equity Method Investments			37		37
Interest Income	7	5	21	(16)	17
Interest Expense	192	325	57	20	594
Income (Loss) before Income Taxes	1,814	592	(459)	(38)	1,909
Income Tax Expense (Benefit)	699	228	9	(10)	926
Income (Loss) from Continuing Operations	1,115	364	(468)	(28)	983
Income from Discontinued Operations, net of tax (including Gain on Disposal)			205		205
Net Income (Loss)	1,115	364	(263)	(28)	1,188
Segment Earnings (Loss)	1,115	360	(263)	(24)	1,188
Gross Additions to Long-Lived Assets	$ 978	$ 761	$ 3	$ 29	$ 1,771
As of December 31, 2008:					
Total Assets	$ 10,266	$ 16,406	$ 3,502	$ (1,125)	$ 29,049

Investments in Equity Method Subsidiaries	$ 35	$	$ 180	$	$ 215
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	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2007:					
Total Operating Revenues	$ 7,422	$ 8,493	$ 167	$ (3,405)	$ 12,677
Depreciation and Amortization	158	591	12	13	774
Operating Income	1,789	957	89	11	2,846
Income from Equity Method Investments			115		115
Interest Income	24	10	14	(12)	36
Interest Expense	185	332	125	85	727
Income (Loss) before Income Taxes	1,676	637	188	(112)	2,389
Income Tax Expense (Benefit)	676	257	176	(45)	1,064
Income (Loss) from Continuing Operations	1,000	380	12	(67)	1,325
Income (Loss) from Discontinued Operations, net of tax (including (Loss) Gain on Disposal)	(8)		18		10
Net Income (Loss)	992	380	30	(67)	1,335
Segment Earnings (Loss)	992	376	30	(63)	1,335
Gross Additions to Long-Lived Assets	$ 715	$ 570	$ 38	$ 25	$ 1,348

Note 22. Related-Party Transactions

The majority of the following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financials statements for Power include transactions with related parties presented as follows:

Related Party Transactions	For the Years Ended December 31, 2009	2008	2007
		Millions	
Revenue from Affiliates:			
Billings to PSE&G through BGS (A)	$ 1,322	$ 1,453	$ 1,163
Billings to PSE&G through BGSS (A)	1,838	2,316	2,208
Total Revenue from Affiliates	**$ 3,160**	**$ 3,769**	**$ 3,371**
Expense Billings from Affiliates:			
Administrative Billings from Services (B)	$ (153)	$ (166)	$ (144)
Total Expense Billings from Affiliates	**$ (153)**	**$ (166)**	**$ (144)**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Related Party Balances	As of December 31, 2009	2008
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts(A)	$ 404	$ 475
Receivables from PSE&G Related to Gas Supply Hedges for BGSS(A)	120	319
Payable to Services(B)	(27)	(26)
Tax Sharing Payable to PSEG(C)	(28)	(38)
Current Unrecognized Tax Receivable from PSEG(C)	3	
Payable to PSEG	(13)	
Accounts Receivable Affiliated Companies, net	**$ 459**	**$ 730**
Short-Term Loan (from) to Affiliate (Demand Note (from) to PSEG)(D)	**$ (194)**	**$ 55**
Working Capital Advances to Services(E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)(C)	**$ 39**	**$ (29)**

PSE&G

The financials statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	For the Years Ended December 31, 2009	2008	2007
		Millions	
Expense Billings from affiliates:			
Billings from Power through BGS(A)	$ (1,322)	$ (1,453)	$ (1,163)
Billings from Power through BGSS(A)	(1,838)	(2,316)	(2,208)
Administrative Billings from Services(B)	(240)	(264)	(238)
Total Expense Billings from Affiliates	**$ (3,400)**	**$ (4,033)**	**$ (3,609)**

As of

December 31,

Related Party Transactions	2009	2008
	Millions	
Payable to Power through BGS and BGSS Contracts(A)	$ (404)	$ (475)
Payable to Power Related to Gas Supply Hedges for BGSS(A)	(120)	(319)
Payable to Power for SREC liability(F)	(7)	
Payable to Services(B)	(42)	(54)
Tax Sharing Receivable from PSEG(C)	13	21
Current Unrecognized Tax Receivable from PSEG(C)	61	55
Receivable from PSEG	3	9
Accounts Payable Affiliated Companies, net	**$ (496)**	**$ (763)**
Working Capital Advances to Services(E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable(C)	**$ (96)**	**$ (82)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G s BGSS and other contractual requirements through March 31,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2012 and year-to-year thereafter. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies. Power and PSE&G believe that the costs of services provided by Services approximate market value for such services.

(C) PSEG and its subsidiaries adopted the accounting guidance for Accounting for Uncertainty in Income Taxes effective January 1, 2007, which prescribes a model for how a company should recognize, measure, present and disclose in its financial statements uncertain tax positions that it has taken or expects to take on a tax return.

(D) Short-term loans are for short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power s and PSE&G s Consolidated Balance Sheets.

(F) In October 2009, the BPU issued a decision reaffirming its 2008 decision that certain BGS suppliers will be reimbursed for the cost they incurred above $300 per SREC during the period June 1, 2008 through May 31, 2010. The BPU order further provided that the excess cost may be passed on to ratepayers. PSE&G has estimated and accrued a total liability for the excess SREC cost of $15 million as of December 31, 2009, including approximately $7 million for Power s share which is included in PSE&G s Accounts Payable Affiliated Companies. Under current guidance, Power is unable to record the related intercompany receivable on its Consolidated Balance Sheet. As a result, PSE&G s liability to Power is not eliminated in consolidation and is included in Other Current Liabilities on PSEG s Consolidated Balance Sheet as of December 31, 2009.

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Note 23. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, Power and PSE&G includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2009	2008	2009	2008	2009	2008	2009	2008
PSEG Consolidated:	Millions							
Operating Revenues	$ 3,920	$ 3,792	$ 2,560	$ 2,550	$ 3,040	$ 3,718	$ 2,886	$ 3,262
Operating Income	927	811	637	177	924	965	633	660
Income (Loss) from Continuing Operations	444	435	311	(166)	488	476	349	238
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax		13		16		180		(4)
Net Income (Loss)	444	448	311	(150)	488	656	349	234
Earnings Per Share:								
Basic:								
Income (Loss) from Continuing Operations	0.88	0.86	0.61	(0.32)	0.96	0.94	0.70	0.46
Net Income (Loss)	0.88	0.88	0.61	(0.29)	0.96	1.29	0.70	0.46
Diluted:								
Income (Loss) from Continuing Operations	0.88	0.85	0.61	(0.32)	0.96	0.94	0.69	0.46
Net Income (Loss)	0.88	0.88	0.61	(0.29)	0.96	1.29	0.69	0.46
Weighted Average Common Shares Outstanding:								
Basic	506	508	506	508	506	508	506	506
Diluted	507	510	507	509	507	508	507	508

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2009	2008	2009	2008	2009	2008	2009	2008
Power:	Millions							
Operating Revenues	$ 2,464	$ 2,475	$ 1,363	$ 1,838	$ 1,564	$ 2,162	$ 1,752	$ 2,008
Operating Income	$ 608	$ 516	$ 402	$ 490	$ 652	$ 703	$ 424	$ 416
Income from Continuing Operations	$ 314	$ 276	$ 246	$ 268	$ 382	$ 388	$ 247	$ 183
Net Income	$ 314	$ 276	$ 246	$ 268	$ 382	$ 388	$ 247	$ 183

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2009	2008	2009	2008	2009	2008	2009	2008
PSE&G:	Millions							
Operating Revenues	$ 2,735	$ 2,618	$ 1,643	$ 1,858	$ 1,943	$ 2,274	$ 1,922	$ 2,288
Operating Income	$ 288	$ 279	$ 150	$ 159	$ 226	$ 248	$ 194	$ 223
Income from Continuing Operations	$ 124	$ 137	$ 44	$ 52	$ 88	$ 98	$ 69	$ 77
Net Income	$ 124	$ 137	$ 44	$ 52	$ 88	$ 98	$ 69	$ 77
Earnings Available to PSEG	$ 123	$ 136	$ 43	$ 51	$ 87	$ 97	$ 68	$ 76

Note 24. Guarantees of Debt

Power s Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents condensed financial information for the guarantor subsidiaries as well as Power s non-guarantor subsidiaries as of December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2009:					
Operating Revenues	$	$ 7,932	$ 494	$ (1,283)	$ 7,143
Operating Expenses	4	5,846	491	(1,284)	5,057
Operating Income (Loss)	(4)	2,086	3	1	2,086
Equity Earnings (Losses) of Subsidiaries	1,208	(20)		(1,188)	
Other Income	57	256	2	(81)	234
Other Deductions	(14)	(120)	(1)		(135)
Other Than Temporary Impairments		(60)			(60)
Interest Expense	(145)	(73)	(29)	80	(167)
Income Tax Benefit (Expense)	87	(861)	5		(769)
Income (Loss) on Discontinued Operations, net of Tax Benefit					
Net Income (Loss)	**$ 1,189**	**$ 1,208**	**$ (20)**	**$ (1,188)**	**$ 1,189**
As of December 31, 2009:					
Current Assets	3,039	5,614	560	(6,871)	$ 2,342
Property, Plant and Equipment, net	61	4,872	1,452		6,385
Investment in Subsidiaries	4,865	1,093		(5,958)	
Noncurrent Assets	253	1,452	52	(151)	1,606
Total Assets	**$ 8,218**	**$ 13,031**	**$ 2,064**	**$ (12,980)**	**$ 10,333**
Current Liabilities	$ 107	$ 7,167	$ 818	$ (6,869)	$ 1,223

Noncurrent Liabilities	522	1,002	150	(152)	1,522
Long-Term Debt	3,121				3,121
Member s Equity	4,468	4,862	1,096	(5,959)	4,467
Total Liabilities and Member s Equity	**$ 8,218**	**$ 13,031**	**$ 2,064**	**$ (12,980)**	**$ 10,333**
For the Year Ended December 31, 2009:					
Net Cash Provided By (Used In) Operating Activities	$ 383	$ 2,520	$ 10	$ (1,255)	$ 1,658
Net Cash Provided By (Used In) Investing Activities	$ 490	$ (1,320)	$ (50)	$ 228	$ (652)
Net Cash Provided By (Used In) Financing Activities	$ (873)	$ (1,202)	$ 66	$ 1,027	$ (982)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2008:					
Operating Revenues	$	$ 8,887	$ 839	$ (1,243)	$ 8,483
Operating Expenses		6,890	710	(1,242)	6,358
Operating Income (Loss)		1,997	129	(1)	2,125
Equity Earnings (Losses) of Subsidiaries	1,120	24		(1,144)	
Other Income	162	501	2	(249)	416
Other Deductions	(13)	(302)		(1)	(316)
Other Than Temporary Impairments		(219)			(219)
Interest Expense	(209)	(147)	(87)	251	(192)
Income Tax Benefit (Expense)	55	(734)	(20)		(699)
Net Income (Loss)	**$ 1,115**	**$ 1,120**	**$ 24**	**$ (1,144)**	**$ 1,115**
As of December 31, 2008:					
Current Assets	2,395	5,507	667	(5,636)	2,933
Property, Plant and Equipment, net	44	4,513	1,486		6,043
Investment in Subsidiaries	5,195	822		(6,017)	
Noncurrent Assets	244	1,166	67	(187)	1,290
Total Assets	**$ 7,878**	**$ 12,008**	**$ 2,220**	**$ (11,840)**	**$ 10,266**
Current Liabilities	$ 371	$ 5,880	$ 1,241	$ (5,637)	$ 1,855
Noncurrent Liabilities	532	935	156	(187)	1,436
Long-Term Debt	2,653				2,653
Member s Equity	4,322	5,193	823	(6,016)	4,322
Total Liabilities and Member s Equity	**$ 7,878**	**$ 12,008**	**$ 2,220**	**$ (11,840)**	**$ 10,266**
For the Year Ended December 31, 2008:					
Net Cash Provided By (Used In) Operating Activities	$ (416)	$ 2,306	$ 5	$ (89)	$ 1,806
Net Cash Provided By (Used In) Investing Activities	$ 918	$ (2,787)	$ (80)	$ 908	$ (1,041)
Net Cash Provided By (Used In) Financing Activities	$ (500)	$ 490	$ 87	$ (821)	$ (744)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2007:					
Operating Revenues	$	$ 7,836	$ 740	$ (1,154)	$ 7,422
Operating Expenses	4	6,152	631	(1,154)	$ 5,633
Operating Income (Loss)	(4)	1,684	109		$ 1,789
Equity Earnings (Losses) of Subsidiaries	981	11		(992)	
Other Income	191	295	3	(247)	$ 242
Other Deductions	(1)	(96)			$ (97)
Other Than Temporary Impairments		(73)			$ (73)
Interest Expense	(197)	(161)	(75)	248	$ (185)
Income Tax Benefit (Expense)	22	(680)	(18)		$ (676)
(Loss) on Discontinued Operations, net of tax benefit			(8)		(8)
Net Income (Loss)	**$ 992**	**$ 980**	**$ 11**	**$ (991)**	**$ 992**
For the Year Ended December 31, 2007:					
Net Cash Provided By (Used In) Operating Activities	$ 1,238	$ 1,595	$ (524)	$ (1,044)	$ 1,265
Net Cash Provided By (Used In) Investing Activities	$ (232)	$ (596)	$ (116)	$ 555	$ (389)
Net Cash Provided By (Used In) Financing Activities	$ (1,006)	$ (1,001)	$ 642	$ 489	$ (876)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A/9A(T). CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, Power and PSE&G have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act) that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer and Chief Financial Officer of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the Chief Financial Officer and Chief Executive Officer of each respective company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, Power and PSE&G

We have conducted assessments of our internal control over financial reporting as of December 31, 2009, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . Management s reports on PSEG s, Power s and PSE&G s internal control over financial reporting is included on pages 183, 184 and 185, respectively. The Independent Registered Public Accounting Firm s report with respect to the effectiveness of PSEG s internal control over financial reporting is included on page 186. This annual report does not include an attestation report of the Independent Registered Public Accounting Firm for Power or PSE&G regarding internal control over financial reporting. Management s report for Power and PSE&G was not subject to attestation by the Independent Registered Public Accounting Firm pursuant to temporary rules of the Securities and Exchange Commission that permit Power and PSE&G to provide only management s report in this annual report. Management has concluded that internal control over financial reporting is effective as of December 31, 2009.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of their financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, each registrant s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING PSEG

Management of Public Service Enterprise Group (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG s assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG s annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

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

Based on the assessment performed, management has concluded that PSEG s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG s financial reporting and the preparation of its financial statements as of December 31, 2009 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2009.

PSEG s external auditors, Deloitte & Touche LLP, have audited PSEG s financial statements for the year ended December 31, 2009 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG s internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer

February 25, 2010

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power s assets that could have a material effect on the financial statements.

In connection with the preparation of Power s annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

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

Based on the assessment performed, management has concluded that Power s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power s financial reporting and the preparation of its financial statements as of December 31, 2009 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2009.

This Annual Report on Form 10-K does not include an attestation report of Power s Independent Registered Public Accounting Firm regarding internal control over financial reporting. Management s report was not subject to attestation by our external auditors pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management s report in the Annual Report on Form 10-K.

/s/ Ralph Izzo
Chief Executive Officer

/s/ Caroline Dorsa
Chief Financial Officer

February 25, 2010

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING PSE&G

Management of Public Service Electric and Gas Company is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G s assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G s annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

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

Based on the assessment performed, management has concluded that PSE&G s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G s financial reporting and the preparation of its financial statements as of December 31, 2009 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2009.

This Annual Report on Form 10-K does not include an attestation report of PSE&G s Independent Registered Public Accounting Firm regarding internal control over financial reporting. Management s report was not subject to attestation by our external auditors pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management s report in the Annual Report on Form 10-K.

/s/ Ralph Izzo
Chief Executive Officer

/s/ Caroline Dorsa
Chief Financial Officer

February 25, 2010

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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 internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the Company) as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index at Item 15 as of and for the year ended December 31, 2009 of the Company and our report dated February 24, 2010 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ Deloitte & Touche LLP
Parsippany, New Jersey
February 24, 2010

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

Name	Age as of December 31, 2009	Office	Effective Date First Elected to Present Position
Ralph Izzo	52	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board, President and Chief Executive Officer (Services)	January 2010 to present
		Chairman of the Board and Chief Executive Officer (Services)	April 2007 to January 2010
		President and Chief Operating Officer (PSEG)	October 2006 to March 2007
		President and Chief Operating Officer (PSE&G)	October 2003 to October 2006
Caroline Dorsa	50	Executive Vice President and Chief Financial Officer (PSEG)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Power)	April 2009 to present
		Executive Vice President and Chief Financial Officer (PSE&G)	April 2009 to present
		Chief Financial Officer (Energy Holdings)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Services)	April 2009 to present
		Senior Vice President, Global Human Health Strategy and Integration (Merck and Co., Inc.)	January 2008 to April 2009
		Senior Vice President and Chief Financial Officer (Gilead Sciences, Inc.)	November 2007 to January 2008
		Senior Vice President and Chief Financial Officer (Avaya, Inc.)	February 2007 to November 2007
		Various positions, last being Vice President and Treasurer (Merck and Co., Inc.)	1987 to 2006

Name	Age as of December 31, 2009	Office	Effective Date First Elected to Present Position
William Levis	53	President and Chief Operating Officer (Power)	June 2007 to present
		President and Chief Nuclear Officer (Nuclear)	January 2007 to October 2008
		Senior Vice President and Chief Nuclear Officer (Salem/Hope Creek)	January 2005 to December 2006
		Vice President Mid-Atlantic Operations of Exelon Nuclear (Exelon Corporation)	July 2003 to December 2004
Ralph LaRossa	46	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Vice President Electric Delivery (PSE&G)	August 2003 to October 2006
R. Edwin Selover(1)	64	Executive Vice President and General Counsel (PSEG)	December 2006 to January 2010
		Senior Vice President and General Counsel (PSEG)	April 2002 to December 2006
		Executive Vice President and General Counsel (PSE&G)	December 2006 to January 2010
		Senior Vice President and General Counsel (PSE&G)	January 1988 to December 2006
		Executive Vice President and General Counsel (Power)	December 2006 to January 2010
		Executive Vice President and General Counsel (Services)	December 2006 to January 2010
		Senior Vice President and General Counsel (Services)	November 1999 to December 2006
Derek M. DiRisio	45	Vice President and Controller (PSEG)	January 2007 to present
		Vice President and Controller (PSE&G)	January 2007 to present
		Vice President and Controller (Power)	January 2007 to present
		Vice President and Controller (Energy Holdings)	January 2007 to present
		Vice President and Controller (Services)	January 2007 to present

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Name	Age as of December 31, 2009	Office	Effective Date First Elected to Present Position
		Assistant Controller Enterprise (Services)	July 2004 to January 2007
		Vice President Planning and Analysis (Energy Holdings)	March 2004 to July 2004
		Vice President and Controller (Energy Holdings)	June 1998 to March 2004
Elbert C. Simpson(1)	61	President and Chief Operating Officer (Services)	January 2007 to January 2010
		Senior Vice President Information Technology (Services)	May 2002 to January 2007
Randall E. Mehrberg	54	President and Chief Operating Officer (Energy Holdings)	June 2009 to present
		Executive Vice President Strategy and Development (Services)	April 2009 to present
		Executive Vice President Planning and Strategy (Services)	September 2008 to April 2009
		Various positions, last being Executive Vice President, Chief Administrative Officer and Chief Legal Officer (Exelon Corporation)	2000 to June 2008
J.A. Bouknight, Jr.	65	Executive Vice President and General Counsel (PSEG)	January 2010 to present
		Executive Vice President and General Counsel (Power)	January 2010 to present
		Executive Vice President and General Counsel (PSE&G)	January 2010 to present
		Executive Vice President and General Counsel (Services)	January 2010 to present
		Partner, Steptoe & Johnson LLP	July 2008 to November 2009
		Executive Vice President and General Counsel (Edison International)	July 2005 to July 2008
		Partner, Steptoe & Johnson LLP	December 1994 to July 2005

(1) Retired in January 2010

Power and PSE&G

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

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Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG s 2010 Annual Meeting of Stockholders, and (ii) compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the headings Election of Directors and Section 16(a) Beneficial Ownership Reporting Compliance in PSEG s definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 8, 2010 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

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

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including Power s, PSE&G s, Energy Holdings and Services respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/investor/governance. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/investor/governance:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and

- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2009, we did not grant any waivers to the Standards.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG s definitive Proxy Statement for the 2010 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 8, 2010 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

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

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading Security Ownership of Directors, Management and Certain Beneficial Owners in PSEG s definitive Proxy Statement for the 2010 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2010, and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading Transactions with Related Persons in PSEG s definitive Proxy Statement for the 2010 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2010 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading Fees Billed to PSEG by Deloitte & Touche LLP for 2009 and 2008 in PSEG s definitive Proxy Statement for the 2010 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2010. Such information set forth under such heading is incorporated herein by this reference hereto.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated s Consolidated Balance Sheets as of December 31, 2009 and 2008 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholders Equity for the three years ended December 31, 2009 on pages 85, 86, 84, 87 and 88, respectively.

b. PSEG Power LLC s Consolidated Balance Sheets as of December 31, 2009 and 2008 and the related Consolidated Statements of Operations, Cash Flows and Capitalization and Member s Equity for the three years ended December 31, 2009 on pages 90, 89, 91 and 92, respectively.

c. Public Service Electric and Gas Company s Consolidated Balance Sheets as of December 31, 2009 and 2008 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholders Equity for the three years ended December 31, 2009 on pages 94, 95, 93, 96 and 97, respectively.

(B) The following documents are filed as a part of this report:

a. PSEG s Financial Statement Schedules:
Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 199).

b. Power s Financial Statement Schedules:
Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 200).

c. PSE&G s Financial Statement Schedules:
Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 200).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:
LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated[(1)]
3b	By-Laws of Public Service Enterprise Group Incorporated effective November 17, 2009[(2)]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987[(3)]
3d	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007[(4)]
4a(1)	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (US Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)[(5)]
9	Inapplicable
10a(1)	Supplemental Executive Retirement Income Plan
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees[(6)]
10a(3)	Employment Agreement with William Levis dated December 8, 2006[(7)]
10a(4)	2007 Equity Compensation Plan for Outside Directors[(8)]
10a(5)	Employee Stock Purchase Plan[(9)]
10a(6)	Deferred Compensation Plan for Directors[(10)]

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10a(7)	Deferred Compensation Plan for Certain Employees(11)
10a(8)	1989 Long-Term Incentive Plan, as amended(12)
10a(9)	2001 Long-Term Incentive Plan(13)
10a(10)	Senior Management Incentive Compensation Plan(14)
10a(11)	Amended and Restated Key Executive Severance Plan(15)
10a(12)	Severance Agreement with Ralph Izzo dated December 16, 2008(16)
10a(13)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009(17)
10a(14)	Employment Agreement with Randall Mehrberg
10a(15)	Stock Plan for Outside Directors, as amended(18)
10a(16)	Compensation Plan for Outside Directors(19)
10a(17)	2004 Long-Term Incentive Plan(20)
10a(18)	Form of Advancement of Expenses Agreement with Outside Directors(21)
11	Inapplicable
12	Computation of Ratios of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable

21	Subsidiaries of the Registrant
22	Inapplicable
23	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31a	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31b	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32a	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code
32b	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC(22)
3b	PSEG Power LLC Limited Liability Company Agreement(23)
3c	Trust Agreement for PSEG Power Capital Trust I(24)

3d	Trust Agreement for PSEG Power Capital Trust II[25]
3e	Trust Agreement for PSEG Power Capital Trust III[26]
3f	Trust Agreement for PSEG Power Capital Trust IV[27]
3g	Trust Agreement for PSEG Power Capital Trust V[28]

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4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein(29)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(30)
10a(1)	Supplemental Executive Retirement Income Plan
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees(6)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(7)
10a(4)	Employee Stock Purchase Plan(9)
10a(5)	Deferred Compensation Plan for Certain Employees(11)
10a(6)	1989 Long-Term Incentive Plan, as amended(12)
10a(7)	2001 Long-Term Incentive Plan(13)
10a(8)	Senior Management Incentive Compensation Plan(14)
10a(9)	Amended and Restated Key Executive Severance Plan(15)
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008(16)
10a(11)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009(17)
10a(12)	2004 Long-Term Incentive Plan(20)
11	Inapplicable
12a	Computation of Ratio of Earnings to Fixed Charges
13	Inapplicable

16	Inapplicable
18	Inapplicable
19	Inapplicable
23	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31c	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31d	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32c	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code
32d	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G(31)
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act(32)
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock(33)
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock(34)
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1995 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock $25 Par as series of Preferred Stock(35)

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3b(1)	By-Laws of PSE&G as in effect April 17, 2007[36]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924, securing First and Refunding Mortgage Bond36 Indentures between PSE&G and First Fidelity Bank, National Association (US Bank National Association, successor), as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	April 1, 1927[37]
4a(3)	June 1, 1937[38]
4a(4)	July 1, 1937[39]
4a(5)	December 19, 1939[40]
4a(6)	March 1, 1942[41]
4a(7)	June 1, 1991 (No. 1)[42]
4a(8)	July 1, 1993[43]
4a(9)	September 1, 1993[44]
4a(10)	February 1, 1994[45]
4a(11)	March 1, 1994 (No. 2)[46]
4a(12)	May 1, 1994[47]
4a(13)	October 1, 1994 (No. 2)[48]
4a(14)	January 1, 1996 (No. 1)[49]
4a(15)	January 1, 1996 (No. 2)[50]

4a(16)	May 1, 1998[51]
4a(17)	September 1, 2002[52]
4a(18)	August 1, 2003[53]
4a(19)	December 1, 2003 (No. 1)[54]
4a(20)	December 1, 2003 (No. 2)[55]
4a(21)	December 1, 2003 (No. 3)[56]
4a(22)	December 1, 2003 (No. 4)[57]
4a(23)	June 1, 2004[58]
4a(24)	August 1, 2004 (No. 1)[59]
4a(25)	August 1, 2004 (No. 2)[60]
4a(26)	August 1, 2004 (No. 3)[61]
4a(27)	August 1, 2004 (No. 4)[62]
4a(28)	April 1, 2007[63]
4a(29)	November 1, 2008
4a(30)	November 1, 2009
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured Medium-Term Notes dated July 1, 1993[64]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (US Bank National Association, successor), as Trustee, providing for Senior Debt Securities[65]

10a(1)	Supplemental Executive Retirement Income Plan
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees[(6)]
10a(3)	2007 Equity Compensation Plan for Outside Directors[(8)]
10a(4)	Employee Stock Purchase Plan[(9)]

10a(5)	Deferred Compensation Plan for Directors(10)
10a(6)	Deferred Compensation Plan for Certain Employees(11)
10a(7)	1989 Long-Term Incentive Plan, as amended(12)
10a(8)	2001 Long-Term Incentive Plan(13)
10a(9)	Senior Management Incentive Compensation Plan(14)
10a(10)	Amended and Restated Key Executive Severance Plan(15)
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008(16)
10a(12)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009(17)
10a(13)	Stock Plan for Outside Directors, as amended(18)
10a(14)	Compensation Plan for Outside Directors(19)
10a(15)	2004 Long-Term Incentive Plan(20)