PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 25, 2011
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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, 2010,

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	22-3663480

Newark, New Jersey 07102-4194
973 430-7000
http://www.pseg.com

001-00973	**PUBLIC SERVICE ELECTRIC AND GAS COMPANY** **(A New Jersey Corporation)** **80 Park Plaza, P.O. Box 570** **Newark, New Jersey 07101-0570** **973 430-7000** **http://www.pseg.com**	**22-1212800**

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
Public Service Electric and Gas Company	**First and Refunding Mortgage Bonds** 9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037 5%, due 2037	New York Stock Exchange

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

(Cover continued on next page)

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(Cover continued from previous page)

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. ¨

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 the 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, 2010 was $15,837,199,627 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 31, 2011 was 506,039,601.

As of January 31, 2011, 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 2011 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 10, 2011, 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. These include, but are not limited to, future performance, revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical. 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, should, hypothetical, potential, forecast, project, 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 13. 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 a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission going forward, 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 in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- adverse changes in the demand for or price of the capacity and energy that we sell into wholesale electricity markets,
- 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 customer usage patterns.

Additional information concerning these factors is set forth in Part I 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 211.

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 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, Inc., 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, 2010

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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 corporation 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 lease investments and the operation of its generation projects.
		Also pursuing solar and other renewable generation projects.
	Has also implemented several programs to improve efficiencies in customer energy use and increase the level of renewable generation within New Jersey.	

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 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	**2010**	**2009**	**2008**
Power	$ 1,136	$ 1,191	$ 1,050
PSE&G	359	325	364
Energy Holdings	49	72	(468)
Other	13	6	(28)
PSEG Income from Continuing Operations	$ 1,557	$ 1,594	$ 918

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

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

Power

Through Power, we seek to produce low-cost energy by efficiently operating our nuclear, coal, gas and oil-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 is provided from Power s firm transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G s requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery gas. Based upon availability, Power also sells gas to others.

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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.

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

We have recently entered into agreements to sell our 2,000 MW of generation capacity in Texas. See Item 8. Financial Statements and Supplementary Data Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies and Note 4. Discontinued Operations and Dispositions, for additional information.

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

Generation Capacity

Our installed capacity utilizes a diverse mix of fuels: 45% gas, 27% nuclear, 18% coal, 9% 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 2010, excluding amounts related to the Texas generation facilities which are being sold, was approximately 56,700 GWh. The following table indicates the proportionate share of generating output by fuel type.

Generation by Fuel Type	**Actual2010**
Nuclear:	
New Jersey facilities	36%
Pennsylvania facilities	16%
Fossil:	
Coal:	
New Jersey facilities	7%
Pennsylvania facilities	10%
Connecticut facilities	2%
Oil and Natural Gas:	
New Jersey facilities	21%
New York facilities	8%
Total	**100%**

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While overall generation has increased over the past several years, the mix by fuel type has changed slightly in recent years due to 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.

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 36% base load, 42% load following and 22% 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	2010 Capacity Factor
Salem Unit 1	85.3%
Salem Unit 2	96.9%
Hope Creek	89.1%
Peach Bottom Unit 2	89.8%
Peach Bottom Unit 3	97.0%

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.

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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 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.

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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 we operate.

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 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources was not available for this facility, our 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. In the past, this coal was also used for our Hudson 2 unit; however, during 2010 we completed the installation of pollution control equipment at that facility which will provide us more flexibility in the types of coal we can use there in the future. For additional information see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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 firm gas transportation contracts to serve our Bethlehem Energy Center (BEC) in New York.

We have 1.3 billion cubic feet-per-day of firm transportation capacity under contract to meet our obligations under the BGSS contract. On an as available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet. 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 2010 and Future Outlook and Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

Power s assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of the Federal Energy Regulatory Commission (FERC):

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. The majority of Power s generating stations operate in PJM.

New York The NYISO 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.

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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, oil 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 historical rise in electric prices 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.

Over the past two years, a decline in wholesale natural gas prices has resulted in lower electricity prices. One of the reasons for the decline in natural gas prices is greater supply from shale production. This trend has reduced margin on forward sales as we recontract our expected generation output.

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 a portion of our capacity 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 operators for those units contribution to reliability. While the RMRs for our units in the ISO-NE expired in 2010, the RMR arrangement for our Hudson 1 generating unit remains in effect and was recently extended until September 2012.

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.

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 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
June 2013 to May 2014	$ 245.00	$ 89.43

Identical prices were set for all zones for the periods from June 2010 to May 2012 under these auctions. For all other periods the prices differ in the various areas of PJM, depending on the constraints in each area of the transmission system, with Keystone and Conemaugh receiving lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey receiving higher pricing.

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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 may 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 outages, etc.);
- increases in transmission capability between zones;
- 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; and
- changes driven by legislative and/or regulatory action, that permit states to subsidize local electric power generation through the consummation of standard offer capacity agreements.

For additional information on our collection of RMR payments in PJM and the RPM and FCM markets, 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. Pricing for the BGS contracts for recent and future periods by purchasing utility, including a capacity component, is as follows:

Load Zone ($/MWh)	2008-2011	2009-2012	2010-2013	2011-2014
PSE&G	$ 111.50	$ 103.72	$ 95.77	$ 94.30
Jersey Central Power and Light	$ 114.09	$ 103.51	$ 95.17	$ 92.56
Atlantic City Electric	$ 116.50	$ 105.36	$ 98.56	$ 100.95
Rockland Electric Company	$ 120.49	$ 112.70	$ 103.32	$ 106.84

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 2014 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 compared to 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 2010, 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 enter into contracts for the future purchase and delivery of our anticipated nuclear fuel and coal needs, which include some market-based pricing components. As of February 15, 2011, 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 2013.

Nuclear and Coal Generation	**2011**	**2012**	**2013**
Generation Sales	90%-95%	40%-50%	15%-30%
Nuclear Fuel Purchases	100%	100%	100%
Coal Supply and Transportation Costs	100%	70%-80%	20%-30%

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 2010.

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 solar power systems throughout our electric service area,

- a program to develop, own and operate solar power systems, 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 2.2 million electric customers and 1.8 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 base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn incentive rates. For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation Transmission Regulation.

Transmission Statistics

December 31, 2010		Historical Annual Load
Network Circuit Miles	**Billing Peak (MW)**	**Growth 2006-2010**
1,357	10,761	-0.1%

Distribution

Our primary business is the distribution of gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described below for 2010. 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 2010 Sales	
Customer Type	**Electric**	**Gas**
Commercial	57%	36%
Residential	33%	61%
Industrial	10%	3%
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, 2010		Historical Annual
	Number of Customers	**Electric Sales and Gas Sold and Transported**	**Load Growth 2006-2010**
Electric	2.2 Million	43,645 GWh	-0.5%
Gas	1.8 Million	3,465 Million Therms	-1.0%

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Supply

Although commodity revenues make up more than 59% 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.

PSE&G procures 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, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A.

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Energy Holdings

Our focus at Energy Holdings is on managing our portfolio of lease investments and exploring opportunities to participate in solar, wind and alternative energy developments in the U.S., as discussed below.

Since 2008, we have pursued opportunities to terminate international leveraged leases with lessees willing to meet certain economic thresholds in order to reduce the cash tax exposure related to these leases. As of December 31, 2010, we had terminated all of these leveraged lease investments and reduced the related cash tax exposure by $1.1 billion. Over the past several years, we have also reduced our international risk by opportunistically monetizing the majority of our previous investments. We are continuing to explore options for our remaining international investment in Venezuela as well as our projects in California, Hawaii and New Hampshire totaling 240 MW. For additional information on these generation facilities, see Item 2. Properties.

Products and Services

The majority of our remaining $1.3 billion of domestic lease investments are energy-related leveraged leases. As of December 31, 2010, the single largest lease investment represented 26% of total lease investments.

Our leveraged 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 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 accounting principles generally accepted in the U.S., 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, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk Credit Risk Energy Holdings, Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables and Note 13. Commitments and Contingent Liabilities.

Through Energy Holdings, we have solar project investments in New Jersey, Florida and Ohio totaling 29 MW, all of which are fully operational. See Item 2. Properties for additional information.

A joint venture owned equally by us and an unaffiliated private developer has been awarded a $3 million grant by the New Jersey Office of Clean Energy (OCE) to advance the development of a wind site to be located approximately 16 miles off the shore of southern New Jersey. Numerous issues will need to be resolved in order to successfully develop such a project. The State of New Jersey has taken steps to stimulate the development of offshore wind generation by enacting the Offshore Wind Economic Development Act. This Act requires BGS and third-party suppliers in New Jersey to procure Offshore Renewable Energy Certificates (ORECs) from qualified off-shore facilities for a 20-year term. The BPU is currently in the process of developing and implementing regulations that will establish an OREC program under which the BPU can review applications to construct, finance and operate off-shore wind facilities.

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We also have invested in a joint venture to license technology that stores energy in the form of compressed air which can later be released to generate electricity through specialized equipment. This technology could be used to optimize an intermittent energy source, such as wind, by storing energy for when it is needed.

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 load requirements. A reduction in load requirements can also be caused by economic cycles, customer migration and other 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. This is now occurring in the State of New Jersey where a new law was enacted on January 28, 2011 establishing a long-term capacity agreement pilot program (LCAPP) which provides for 2,000 MW of subsidized base load or mid-merit electric power generation. This bill may have the effect of artificially depressing prices in the competitive wholesale market and thus has the potential to harm competitive markets, on both a short-term and a long-term basis. Other states, such as Maryland, are also examining similar programs. Construction of new subsidized local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints. The lack of consistent rules in energy markets can negatively impact the competitiveness of our plants.

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. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. While our generation fleet is relatively low-emitting, additional restrictions could have a negative impact on certain of our units, including our coal units.

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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, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator, the California ISO and the PJM region, have either implemented or are considering implementing changes to their respective regional transmission planning processes that will enable the construction of large amounts of transmission to move renewable generation to load centers. The FERC is considering ordering all FERC-jurisdictional regions to effectuate such changes to the planning processes to facilitate the integration of renewable resources. See discussion in Regulatory Issues Federal Regulation below.

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.

Changes in the current policies for building new transmission lines, such as the proposal by FERC to eliminate provisions for us to have the right of first refusal to construct projects in our service territory, could result in additional competition to build transmission lines in our area in the future and would allow us to seek opportunities to build in other service territories. Moreover, as discussed in Regulatory Issues Federal Regulation below, the court s elimination of national electric transmission corridors may impact upon future transmission build.

EMPLOYEE RELATIONS

As of December 31, 2010, we had approximately 9,965 employees within our subsidiaries, including 6,451 covered under collective bargaining agreements.

Employees as of December 31, 2010

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,292	1,178	18	1,026
Union	1,511	4,931	0	9
Total Employees	**2,803**	**6,109**	**18**	**1,035**
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.

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 and the generation and energy trading subsidiaries of Power 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

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the primary energy source is renewable, biomass, waste, or geothermal resources. QFs must meet certain criteria established by FERC. We own various QFs through Energy Holdings. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates RTOs/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 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 filed for an update of its MBR authority in December 2010. Interventions and comments with respect to this MBR filing are due at the FERC by the end of February. A decision is expected in 2011.

- ***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. On November 11, 2010, PJM officially notified Power that it will need the Hudson 1 generating station to remain in service through September 1, 2012 to ensure grid reliability during the summer of 2012 given the delays associated with the Susquehanna-Roseland project. In January 2011, Power filed at FERC for extension of the RMR agreement for Hudson Unit 1 through September 1, 2012.

In ISO-NE, many owners of generation facilities have also filed for RMR treatment. During 2010, we collected FERC-approved monthly payments for the Bridgeport Harbor Station Unit 2 and the New Haven Harbor Station under agreements that expired in June 2010.

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 Market Issues

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 were challenged in court by various state public utility commissions, including the BPU. On February 8, 2011 the DC Circuit Court of Appeals issued a decision upholding FERC orders denying this challenge to the transitional auction results. Moreover, the mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active, and there is currently significant discussion about the future role of demand response in the RPM market.

Pursuant to a settlement that established the design of ISO-NE s market for installed capacity and which was 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. Power has challenged in court the results of the ISO-NE s first forward capacity auction, arguing that its units received inadequate compensation notwithstanding the location of its resources in a constrained area. This case is pending at the D.C. Circuit Court of Appeals. Power and other generators have also filed a complaint at FERC regarding the ISO-NE s capacity market design, alleging that it insufficiently reflects locational capacity values. This complaint is also pending.

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.

Recent legislative developments in the State of New Jersey have the potential to adversely impact RPM prices. On January 28, 2011, New Jersey enacted a new law establishing LCAPP. This law calls for New Jersey electric distribution companies such as PSE&G to subsidize 2,000 MWs of new generation capacity in New Jersey for a term of up to 15 years. The law also provides for the BPU to hold an expedited process to select generators to receive these subsidies and to perform a net benefits test examining economic, community and environmental benefits associated with generating projects. The BPU has commenced this process, which requires the submission of binding generator bids by March 7, 2011 and selection of eligible generators by March 30, 2011. Once generators are selected, the electric distribution companies will then be required to enter into irrevocable, financially settled, standard offer capacity agreements (SOCA). The SOCA will require that the generator bid in and clear the PJM RPM base residual auction in each year of the SOCA term. The SOCA will provide for the electric distribution companies to make capacity payments to, or receive capacity payments from, the generators as calculated based on the difference between the RPM clearing price for each year of the term and the price bid and accepted for that generator in the BPU process.

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The LCAPP legislation is being challenged both at FERC and in court. In February, PSEG and a group of other generators filed a complaint at the FERC seeking to prevent the subsidized generation from interfering with the wholesale capacity market and a case in federal district court arguing that the legislation is unconstitutional and should be invalidated. Both actions are pending. In addition, PJM has made a filing at FERC that, if accepted by FERC, would significantly mitigate the effect of this subsidized generation on the RPM market clearing prices for capacity.

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 certain large scale transmission investments. For additional information on our transmission rates and the annual true-ups, see Item 7. MD&A   Overview of 2010 and Future Outlook.

Transmission Policy Developments   In June 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to modify current transmission planning and cost allocation processes. Specifically, FERC has proposed that transmission planning take into account   public policy   requirements established by state or federal laws or regulations, such as state Renewable Portfolio Requirements. FERC has also questioned whether it is appropriate for transmission planning to utilize a   bright line   test to identify needed transmission projects or whether   flexible criteria   should be used. These proposed changes would likely result in more transmission being planned and constructed.

FERC has also proposed to eliminate provisions in FERC-approved tariffs or agreements that permit a transmission owner within whose franchised service territory a transmission project is being constructed to exercise a   right of first refusal   to construct the project. FERC has not yet acted to issue a Final Rule. There are also two pending FERC litigated proceedings, in which we are a party, addressing and challenging this proposed change to the   right of first refusal.   A change in FERC rules or adverse decisions in these proceedings could result in third parties constructing transmission within PSE&G   s service territory in the future.

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 up to $750 million, and PJM had originally directed that the line be placed into service by June 2012. 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. In February 2010, we received approval from the BPU to construct our portion of the project, which was memorialized by a written order in April 2010. Regarding environmental approvals, 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 which was approved by the New Jersey Department of Environmental Protection (NJDEP) in January 2010. However, we have not received certain environmental approvals that are required for each of the Eastern and Western segments of the line and believe it is unlikely that we will obtain these approvals until late 2012, at the earliest. The Western portion of the line also requires certain permits from the National Park Service, whose review is not expected to be completed until late 2012. Consequently, at this time, we do not expect the Eastern portion of the line to be in service before June 2014, and do not expect the Western portion to be in service before June 2015. Further delays are possible for both portions. Delays in the construction schedule could impact the timing of expected transmission revenues.

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On February 3, 2011, certain environmental groups that were parties to the BPU proceeding approving the Susquehanna-Roseland line filed a motion to reopen the agency record on the grounds of changed circumstances, including the delay in construction of the project and PJM s issuance of a new load forecast report. PSE&G believes that there are no grounds to reopen the record. The same parties have also appealed the BPU order to the NJ Appellate Division and this appeal remains pending.

FERC has granted our request for incentive rate treatment for the Susquehanna-Roseland line, including an adder of 125 basis points above our base ROE, recovery of 100% of Construction Work in Progress (CWIP) 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.

In December 2008, PJM approved another 500 kV transmission project, originating in Branchburg and ending in Hudson County, New Jersey, with an estimated cost of $1.1 billion. In December 2009, FERC granted our request for the same incentive rate treatment on this project as the Susquehanna-Roseland line. Subsequently, PJM approved a modified 230 kV project, in place of the 500 kV line, originating in Roseland and terminating in Hudson County, at an estimated cost of up to $700 million. The project has an expected in-service date of June 2015. Development and siting activities for this project are expected to commence in 2011. In November 2010, we filed a notice with FERC regarding the change in project scope. The BPU and the New Jersey Division of Rate Counsel each filed objections to the continuation of the previously-awarded rate incentives to the reconfigured project. We have filed responsive pleadings and believe that the modified project should be eligible for the same rate incentives as the original project, but the matter remains pending at FERC.

PJM has approved in its Regional Transmission Expansion Plan several other 230 kV transmission projects to be constructed by PSE&G. PSE&G filed at FERC for recovery of CWIP in rate base for four of these projects (Burlington-Camden project, West Orange project, Middlesex Switch Rack project and Bayonne-Marion project) and 100% abandonment cost recovery for these projects. On December 30, 2010, the FERC denied PSE&G s request without prejudice, finding that PSE&G had not met the requirements for incentive treatment on a project-by-project basis and affording PSE&G the option to re-file and justify the requested incentives on a project-by-project, rather than on an aggregate, basis. PSE&G is currently considering this option.

In February 2011, the United States Court of Appeals for the 9th Circuit issued a decision vacating the U.S. Department of Energy s (DOE) 2006 Congestion Study and the two national transmission corridor designations resulting from the study, including the Mid-Atlantic Corridor which encompasses all of the State of New Jersey. FERC back-stop siting authority permits an entity building transmission to site the project at FERC under certain circumstances, including a State s failure to act within one year. However, since this authority only attaches to transmission located within a DOE-designated corridor, FERC back-stop siting authority is now unavailable to companies building transmission in New Jersey, such as PSE&G.

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. Each 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 were denied. The case was then remanded to FERC for further proceedings. FERC has not yet issued a decision. 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 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. Our California generation assets, as well as our New Jersey utility operations, have already undergone formal audits, and our generation assets in PJM, ISO-NE and the NYISO 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 and a challenging one. As new standards are developed and approved, existing standards are revised and registration requirements are modified which could increase our compliance responsibilities.

Commodity Futures Trading Commission (CFTC)

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was passed in an attempt to reduce systemic risk in the financial markets thereby preventing future financial crises and market issues such as those experienced recently. As part of this new legislation, the SEC and the CFTC will be implementing new rules to enact stricter regulation over swaps and derivatives since many of the issues experienced were caused by derivative trading in connection with mortgage loans. Additionally, the Dodd-Frank Act will require many swaps and other derivative transactions to be standardized and traded on exchanges or other Derivative Clearing Organizations (DCOs).

CFTC has issued NOPRs on many of the key issues, including:

- defining swap dealers and major swap participants;
- the end-user exception from clearing requirements;
- position limits; and
- reporting requirements.

A number of other critical issues, such as the defining swap and capital and margin requirements, still need to be addressed.

Exchanges and DCOs typically require full collateralization of all transactions taking place on the exchange or DCO. Although the Dodd-Frank Act specifically recognizes a commercial end user exemption from posting additional collateral in the bilateral Over the Counter swap and derivative markets, we cannot assess the exact scope of the new rules until the SEC and CFTC issues them. Under the current NOPRs, the broad definition of swap dealer could result in us being classified as a dealer, which would limit the benefits of the commercial end-user exemption recognized in the Act. We expect the final rules to be issued later in 2011. We believe that any regulatory change that deviates from the original intent would need to be addressed by additional legislation. We will carefully monitor these new rules as they are developed to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

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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

In 2009, we also filed an application for an Early Site Permit for a new nuclear generating station to be located at the current site of the Salem and Hope Creek generating stations.

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 and Pennsylvania due to our ownership of generation and/or transmission facilities in those states.

Rates

Electric and Gas Base Rates In May 2009, we petitioned the BPU for an increase in electric and gas distribution base rates. We filed an update in March 2010 requesting an increase of $140 million and $64 million for electric and gas, respectively.

In June 2010 the BPU adopted a stipulation settling the electric portion of our base rate case, including the electric revenue requirement, the capital structure, re-setting the electric component of the Capital Adjustment Charges (CAC), as well as accepting the modifications to the electric tariff. The new electric rates were put into effect on June 7, 2010. The settlement included a $73.5 million increase in annual electric revenues and an allowed ROE of 10.3%. In July 2010, the BPU approved the gas revenue requirement and rate design set forth in the stipulation, including resetting the gas CAC and an allowed ROE of 10.3%, resulting in a $26.5 million increase effective July 9, 2010. The BPU also approved PSE&G s gas weather normalization clause.

Retail Gas Transportation Rates In July 2010, as part of PSE&G s gas base rate proceeding, the BPU ordered a supplemental and expedited review of certain issues related to the gas transportation rate that PSE&G charges to Power. Also in July, a complaint was filed by an independent power generator against Power at FERC related to the gas transportation rate.

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On December 16, 2010, the BPU approved a settlement that resolved all remaining issues in PSE&G s base rate case. The settlement provisions include the following:

- there will be no retroactive adjustments or refunds made by PSE&G with respect to the gas delivery charges,
- the natural gas delivery rate charged by PSE&G to Power may not be altered for any reason until after the conclusion of a BPU generic proceeding to establish rules governing discounting of such agreements and a subsequent filing implementing any such rule, provided however, that if the generic proceeding is not completed within 24 months, PSE&G may file with the BPU to seek a change in rates for gas transportation service to Power, and
- PSE&G to prospectively charge certain other generating facilities a rate comparable to the charges to Power for a period of three years.

The settlement also provides for a release of all claims in the complaint filed at FERC, which has been withdrawn.

The BPU has commenced a generic proceeding to evaluate the process and standards for all utilities to provide discounts to their gas delivery customers. The issues being addressed as part of this proceeding include:

- the legality of charging discounted utility gas distribution rates,
- the legality of established discounted gas utility distribution rates through contracts and whether current or future contracts may be evergreened ,
- the criteria and process that the BPU should establish to determine whether or not an entity has an ability to bypass the utility s gas distribution system,
- whether other considerations unrelated to system bypass should be used to justify discounts and, if so, what rates should be charged, and
- the applicability of Societal Benefits Charges (SBC), Regional Greenhouse Gas Initiative (RGGI) and Capital Adjustment Charges (CAC) prospectively to customers with an ability to bypass the utility s gas distribution system.

Several stakeholder meetings have been held and briefs were submitted at the end of January 2011.

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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 is 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 SBC and Non-utility Generation Charges (NGC) clauses are detailed in the following table:

Rate Clause	**2010 Revenue**	**(Over) Under Recovered Balance as of December 31, 2010**
	Millions	
Energy Efficiency and Renewable Energy	$ 205	$ (14)
Universal Service Fund (USF)	161	23
Social Programs	46	65
Total SBC	**412**	**74**
Remediation Adjustment Charges (RAC)	36	119
NGC	176	66
Gas Weather Normalization	0	(9)
Total	**$ 624**	**$ 250**

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, and the USF. In addition, the electric SBC includes a Social Programs component. All components include interest on both over and under recoveries.

Remediation Adjustment Clause (RAC) The RAC recovers the costs to clean up manufactured gas plants.

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

Gas Weather Normalization Clause Effective with the 2010 base rate case the BPU approved the implementation of a gas weather normalization clause. The purpose of the clause is to remove the gas earnings volatility caused by variations in the weather over the winter period, which is defined as October through May. To the extent that the cumulative winter period is colder than normal, we will be required to refund to customers the excess margin collected as a result of the weather. To the extent that the cumulative winter period is warmer than normal, we have the opportunity to collect from customers the resulting margin shortfall subject to an earnings test. In this instance, collections from customers would only be allowed to the extent they did not cause our return on equity from our gas operations to exceed 10.3%. The earnings test is measured using a 12-month period beginning October 1.

The cumulative weather for October through December 2010 has been colder than normal. As a result, at December 31, 2010, we have recorded a regulatory liability of $9 million to defer the excess margin collected for that period. The ultimate amount refunded to customers, if any, will depend on the weather for the balance of the winter period.

Recent Rate Adjustments

USF/Lifeline The USF is an energy assistance program mandated by the BPU 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. On June 30, 2010, the State s electric and gas utilities filed to reset the statewide rates for the USF and the Lifeline program.

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The filed rates were subsequently updated and approved effective November 1, 2010 in a written Order dated October 20, 2010. The filed rates were set to recover $215 million on a statewide basis. Of this amount, the revised statewide electric rates will recover $150 million and the statewide gas rates will recover $65 million. The rates for the Lifeline program are set to recover $73 million; $49 million and $24 million for electric and gas respectively. We earn no margin on the collection of the USF and 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. The Administrative Law Judge (ALJ) issued an initial decision in April 2010 that recommended a revenue increase of $119 million and a disallowance of approximately $254,000 in PJM costs from the NGC and approximately $540,000 of interest that accrued on the electric SBC. Although PSE&G filed exceptions to the recommendation, the BPU issued a written order in June 2010, adopting the ALJ s initial decision. PSE&G filed a notice of appeal in August 2010 regarding the disallowances related to the NGC and electric SBC. We cannot predict the outcome of this appeal.

In August 2010, PSE&G made its 2010 annual SBC/NGC filing requesting an $85.4 million electric increase and a $17.2 million gas decrease. This matter was transferred to the Office of Administrative Law (OAL) for establishment of a procedural schedule and hearings.

On February 11, 2011, PSE&G filed a stipulation of settlement with the ALJ. The stipulation was executed by all parties and will allow PSE&G to increase its electric SBC/NGC rates by $85.4 million and decrease its gas SBC rates by $17.2 million, both on an annual basis. The stipulation must be approved by the ALJ and the BPU.

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 million and $11 million, respectively. In August 2010, the BPU issued an order approving a settlement agreement which provides for the recovery of $24 million for the twelve months ended July 2009.

In November 2010, we filed a RAC 18 petition with the BPU requesting an increase in electric and gas RAC rates of approximately $3 million and $1 million, respectively. This matter was transferred to the OAL for establishment of a procedural schedule.

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 82% 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.

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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:

	2008	2009	2010	2011
36 Month Terms Ending	May 2011	May 2012	May 2013	May 2014(A)
Eligible Load (MW)	2,800	2,900	2,800	2,800
$ per kWh	0.11150	0.10372	0.09577	0.09430

(A) Prices set in the February 2011 BGS Auction are effective on June 1, 2011 when the 2008 BGS agreements expire.

The BPU once again approved the auction process for 2011, however two changes were made. The BPU determined that the additional charge known as the Retail Margin charge should be eliminated and the threshold for hourly pricing should be lowered to include non-residential customers with a peak load of 750 kW or more. The Retail Energy Supply Association has filed a Petition for the BPU to reconsider the Retail margin portion of the decision.

For additional information, see Item 8. Financial Statements and Supplementary Data Note 6. Regulatory Assets and Liabilities and Note 13. 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 July 2010, PSE&G self-implemented a reduction in the BGSS rate. The reduction targets an approximate $90 million decrease in the BGSS deferred balance on an annual basis. The reduction in the BGSS-Residential Service Gas (RSG) Commodity Charge for a typical gas residential heating customer was a decrease of approximately 5%.

Also in July 2010, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $123 million, excluding sales and use tax, to be effective October 1, 2010. This represented a reduction of approximately 6.8% for a typical residential gas heating customer. The new BGSS rate was approved by the BPU in September 2010, on a provisional basis, and was made effective immediately. Subsequent to these two reductions, PSE&G filed and self-implemented an additional reduction to the BGSS rate in December. This reduction targeted an approximate $69 million decrease in the BGSS deferred balance. The reduction in the BGSS-RSG Commodity Charge for a typical gas residential heating customer was a decrease of approximately 5%. We are awaiting BPU approval finalizing the BGSS-RSG rates for the current period.

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.

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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.

On October 1, 2010, we filed a petition with the BPU for an increase in the RGGI Recovery Charge (RRC), seeking to recover approximately $48 million in electric revenue and $11 million in gas revenue on an annual basis. The required annual filing seeks to reset the RRC rate components for five programs. These include Carbon Abatement, the EEE Stimulus Program, the Demand Response Program, Solar 4 All, and the Solar Loan II Program.

During 2010, the Governor of New Jersey directed the BPU to review the State s current EMP. We expect the BPU to release a new draft EMP during the first quarter of 2011 with a final plan expected to be completed later in the year. We cannot predict what modifications or new goals will be included in the new EMP or the potential impacts to our businesses.

Solar Initiatives In order to spur investment in solar power in New Jersey and meet renewable energy goals under the existing 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 BPU approved an expansion of the program in November 2009. 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 $250 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2010, we have provided a total of $70 million in loans for 196 projects representing 19 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 $465 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, 2010, 15 MW of solar panels had been installed on distribution poles with an investment of approximately $110 million. In addition during 2010, 13 MW representing 11 projects were placed in service with an investment of approximately $70 million. An additional 6 MW is expected to be placed into service in the first quarter of 2011 and additional projects are in various stages of negotiation and development.

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 the end of the third year by a total of 600 MW, of which we are responsible for 55% (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.

In October 2010 we petitioned the BPU to expand the number of participants in the residential cycling program by 57,000 for a total of approximately 225,000 residential participants, due to a lower per-unit installation cost. The request is still pending. The remainder of our original filing has been inactive at the BPU since July 2009. As of December 31, 2010, we had installed approximately 19 MW.

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.

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 anticipated approximately $166 million in energy efficiency capital expenditures over an 18-month period. The program provides for a charge for recovery of program expenditures plus an allowed return. As of December 2010, $100 million of the $166 million had been invested. The 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.

In January 2011, we filed for approval of an Energy Efficiency Economic (EEE) Extension Program to extend three central EEE subprograms (multi-family, municipal and hospital) which are currently in operation and are fully subscribed with a backlog of customer applications. We proposed to extend the subprograms offerings under the same process, terms and conditions as currently approved while seeking additional capital expenditures of approximately $95 million.

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. For each year of the program we will file a petition on October 1 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 resulted in a net annual revenue increase of $1.9 million in 2010. The petition filed in October 2010 for setting the recovery charges for 2011 is still pending. As of December 31, 2010, $20 million of the approved $46 million investment had been spent on energy efficiency measures.

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. We made this filing 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. The CAC will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting.

PSE&G spent $180 million on approved infrastructure projects in 2009 and collected approximately $11 million through the CAC.

The CAC rates were adjusted on a provisional basis on January 1, 2010. At the conclusion of PSE&G s base rate case in June and July 2010, the infrastructure projects that were placed in service through the end of 2009 were rolled into rate base rate and the CAC rates were adjusted accordingly, again on a provisional basis. PSE&G spent $408 million on approved infrastructure projects in 2010 and collected approximately $36 million through the CAC.

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In November 2010, PSE&G made its second annual filing seeking an update to the CAC rates that would provide for approximately $25 million through June 2011 to cover the remaining $108 million infrastructure investments under the program.

Also in November 2010, we filed for an extension of the gas Capital Stimulus program, seeking BPU approval for approximately $78 million in gas infrastructure investments over a two-year period. We also filed to roll-in to rate base the unrecovered Capital Stimulus expenditures for projects that would be placed in service by June 30, 2011. If approved, this roll-in will result in an increase in the electric and gas base rates of $41 million and $22 million, respectively, with a corresponding reduction in the CAC. We are awaiting a decision on this matter.

In February 2011, we filed for an extension of the electric Capital Stimulus program, seeking BPU approval for approximately $229 million in electric infrastructure investments over a 26-month period.

Consolidated Tax Adjustments

New Jersey is one of five states that make consolidated tax adjustments. These adjustments are intended to allocate tax benefits realized by non-regulated subsidiaries to utility customers under certain circumstances. The generic proceeding that we originally anticipated during 2010, which was expected to address the appropriateness of the adjustment and the methodology and mechanics of the calculation, has not yet commenced and no schedule has been set for it.

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. We expect that a draft report will be issued during 2011. The report can be expected to include recommendations for changes in practices at PSE&G and its 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 conducted audits of electric deferred balances that occurred during the four year transition period from 1999 through 2003. 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. Effectively, this audit was closed with the resolution of the Market Transition Charge issues. See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for additional information.

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. In August 2010 we received a No Action letter from the BPU stating that no material issues were found and the BPU staff now considers the audit to be closed.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. 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 known 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.

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

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

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 13. Commitments and Contingent Liabilities.

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.

Clean Air Interstate Rule (CAIR) Since 2009, the EPA has regulated nitrogen oxide ($NO_{x)}$ emissions and starting in 2010, regulated sulfur dioxide ($SO_{2)}$ emissions to reduce interstate air pollution transport among the 28 central and northeastern states and the District of Columbia. Our generating stations in Connecticut, New Jersey and New York are affected sources in the regulation. The purpose of the regulation is to improve Ozone and Fine Particulate (PM2.5) air quality within states that have not demonstrated achievement of National Ambient Air Quality Standards (NAAQS). CAIR was implemented through a cap-and-trade program and to date the impact has not been material to us as the allowances allocated to our stations were sufficient. If 2011 operations are similar to 2009 and 2010, it is expected that the impact to operations from CAIR will not be significant. Starting January 2012, CAIR is expected to be replaced by the Clean Air Transport Rule (see below).

New Jersey NOx Regulation: High Electric Demand Day (HEDD) 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 has a significant impact on Power s generation fleet, as it imposes NO_x emissions limits that will require significant capital investment for controls or the retirement of 102 combustion turbines (approximately 2,000 MW) and five older New Jersey steam electric generation units (approximately 800 MW) by April 2015. We have been working with the NJDEP throughout the development of this rulemaking to minimize financial impact and to provide for transitional lead time to address the retirement of electric generation units. Power cannot predict the financial impact resulting from compliance with this rulemaking.

Clean Air Transport Rule (CATR) In August 2010, the EPA proposed the CATR to limit emissions in 32 states that contribute to the ability of downwind states to attain and/or maintain the 1997 and 2006 PM2.5 NAAQS and the 1997 ozone NAAQS. Beginning in 2012, emissions reductions would be governed by this rule, rather than the former CAIR. By 2014, the EPA estimates that this rule, along with other concurrent state and EPA actions, would significantly reduce power plant SO_2 and NO_x emissions. The EPA has acknowledged that further reductions may be necessary to meet expected future changes to Ozone and PM2.5 NAAQS. The proposed rule includes various options for rule form including cap and trade. The final rule is expected in 2011. The outcome of the EPA s rulemaking and impact to PSEG cannot be predicted at this time.

The CAIR cap and trade program for SO_2 emissions made use of allowances created under the Acid Rain Program (ARP). Emission reductions beyond those required by the ARP were to be achieved by increasing the surrender ratio for SO_2 allowances from 1 allowance per ton of SO_2 emissions to 2 allowances per ton in 2010 and 2.86 allowances per ton in 2015, thereby effectively reducing the overall amount of SO_2 that could be emitted under the ARP cap. In July 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and limited the EPA s ability to use SO_2 allowances created under the ARP in any successor program to CAIR.

Hazardous Air Pollutants Regulation In accordance with a court ruling, the EPA is expected to propose a Maximum Achievable Control Technology (MACT) regulation by March 2011 and finalize it by November 2011. This regulation will include mercury reduction. In preparation for this action, the EPA solicited extensive stack-testing information from many coal and oil fired electric generation units through a mandatory Information Collection Request (ICR). PSEG participated in this ICR and submitted the required information in 2010. According to the prescriptive MACT process, the EPA will select an emission rate from the best performing units, by pollutant and/or surrogate, and units within a given category yet to be determined will have to have a lower emission rate than the selected rate by a set date, typically three to five years after the final rule. The impact from this expected rule cannot be determined at this time.

Climate Change

Regional Greenhouse Gas Initiative (RGGI) 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 CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, and 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 (GHG) program that may or may not supplant RGGI. For the first three-year compliance period, we have acquired sufficient allowances to compensate for CO_2 emissions from affected sources.

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.

***CO_2 Regulation Under the Clean Air Act* (CAA)** In April 2010, the EPA and the National Highway Transportation Safety Board (NHTSB) jointly issued a final rule to regulate GHG emissions from certain motor vehicles (Motor Vehicle Rule). Under the CAA, the adoption of the Motor Vehicle Rule would have automatically subjected many emission sources, including ours, to CAA permitting for new facilities and major facility modifications that increase the emission of GHGs, including CO_2 However, guidance issued by the EPA in March 2010 interpreted the CAA to require permitting for GHGs at other facilities, such as ours, only when the Motor Vehicle Rule takes effect in January 2011. In May 2010, the EPA finalized a Tailoring Rule that will phase in, beginning in 2011, the application of this permitting requirement to facilities such as ours. The significance of the permitting requirement is that, in cases where a new source is constructed or an existing source undergoes a major modification, the owner of the facility would need to evaluate and perhaps install best available control technology (BACT) for GHG emissions.

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In November 2010, the EPA published guidance to state and local permitting authorities to undertake BACT determinations for new and modified emission sources. The guidance does not specify the specific technology or technologies that should be considered BACT. The guidance does emphasize the use of energy efficiency, and specifically states that the technology of storing CO_2 under the earth, also known as carbon capture and storage, is not yet mature enough to be considered a viable alternative at this stage. The practical effect of this guidance document is unclear in the context of applying the Tailoring Rule to specific facilities. In December 2010, the EPA also announced a schedule for proposed New Source Performance Standards (NSPS) for GHGs from power plants and refineries. For electric generating units, the EPA must propose a rule by July 2011, and issue a final rule by May 2012. The NSPS applies to both the construction of new sources as well as the modification of existing sources. Unlike BACT, NSPS sets a floor which all facilities must meet for a particular pollutant. Since a proposed rule has not been published, the outcome of the rulemaking and its significance to the company cannot be predicted.

Climate Related Legislation The federal government may consider legislative proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Proposed provisions may present material risks and opportunities to our businesses. The final design of any legislation will determine the impact on us, which we are not now able to reasonably estimate.

CO_2 Litigation In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving our companies could be material to the future liability of energy companies. 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 to us could be material.

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 and Connecticut, 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.

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 through 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 13. Commitments and Contingent Liabilities.

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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. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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. Under the contracts, the DOE was required to begin taking possession of the spent nuclear fuel by no later than 1998. The Nuclear Waste Policy Act requires the DOE to perform an annual review of the Nuclear Waste Fee to determine whether that fee is set appropriately to fund the national nuclear waste disposal program. In October 2009 the DOE stated that the current fee of 1/10 cent per kWh was adequate to recover program costs. In April 2010, we joined the Nuclear Energy Institute and fifteen other nuclear plant operators in petitioning the United States Court of Appeals for the District of Columbia District to review the DOE decision to continue to collect the Nuclear Waste Fee at the current rate. On December 13, 2010, the Court dismissed the petition based in part on the fact that DOE had completed its fee adequacy review. In its decision, the Court still allows for a challenge to the adequacy of the assessment. The petitioners are currently evaluating legal options.

The Nuclear Waste Fee litigation is not expected to have any effect on Power s September 2009 settlement agreement with DOE applicable to Salem and Hope Creek under which Power will be reimbursed for past and future reasonable and allowable costs resulting from the DOE delay in accepting spent nuclear fuel for permanent disposition. 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 on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

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. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, 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.

Coal Combustion Residuals (CCRs) In June 2010, the EPA formally published a proposed rule in the Federal Register offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste and the other two options are variations of a non-hazardous designation. All options communicate the EPA s intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human health and the environment. The outcome of the EPA rulemaking cannot be predicted.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Note 22. 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 effect on 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 businesses.

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 businesses, 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.

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

- ***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. We have been, and will continue to be, periodically audited by NERC for compliance. FERC can impose penalties up to $1 million per day per violation. Further, 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 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.

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 are 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 typically 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 usually translate into significant changes in the wholesale price of electricity.

Over the past two years wholesale prices for natural gas have dropped dramatically. One of the reasons for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have led to lower electricity prices, which has reduced our margins as nuclear and coal commodity and operating costs have not declined similarly. Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.

In recent years, generation by our coal units was also adversely affected by the relatively lower 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, 2010, it may have had to provide approximately $828 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the Commodity Futures Trading Commission which are expected to be implemented later in 2011.

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.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our businesses, 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 (GHG) produced by our fossil generation facilities Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. Legislation enacted in the states where our generation facilities are located 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 GHG 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.

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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 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 Salem, 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.

The EPA will be proposing rules this year which will regulate cooling water intake structures. In accordance with a settlement with environmental groups, EPA is scheduled to publish a final rule by July 27, 2012. The impact of this rulemaking could significantly impact states permitting decisions on whether to require closed cycle cooling and could materially increase our cost of compliance.

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. Recent amendments to New Jersey law now place affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances. While those amendments do not change our liability, they do impact the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow.

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 13. 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 pollutants. 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 a CCR 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. In June 2010, the EPA formally published a proposed rule in the Federal Register offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste and the other two options are variations of a non-hazardous designation. All options communicate the EPA s intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human

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health and the environment. The outcome of the EPA rulemaking cannot be predicted. 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.

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.

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, significant property damage and/or a change in the regulatory climate. We have nuclear units at 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

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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 and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In addition, recent legislative developments in the State of New Jersey have the potential to adversely impact RPM prices. In January 2011, New Jersey enacted a law establishing a LCAPP which provides for the construction of 2,000 MW of subsidized base load or mid-merit electric power generation. Electric utilities will be required to enter into irrevocable, financially settled, standard offer capacity agreements with a term of up to 15 years requiring them to make or receive capacity payments to or from the generators.

The LCAPP may have the effect of artificially depressing prices in the competitive wholesale market. PJM s Independent Market Monitor has released a report estimating that the impact of bidding 2,000 MW of capacity in New Jersey as a price taker would be a reduction in capacity market revenues to PJM suppliers of more than $2 billion in the first year.

Many other 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. 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 are seeking inclusion in regional transmission planning processes, with the potential to move lower-cost generation to eastern markets, including New Jersey and New York. Moreover, the FERC has a pending rulemaking proceeding to consider requiring changes to transmission planning processes so that more transmission can be built to facilitate renewable generation development. In addition, the DOE-funded Eastern Interconnection Planning Collaborative (EIPC) continues its efforts to study 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.

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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,
- utilities,
- 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 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 PV (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.

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.

Our generation 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 exposure 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.

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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 will need continued access to debt capital from outside sources 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. A decline in the market value of our pension assets similar to the one experienced in 2008 could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

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 recent years 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.

We may be adversely affected by equipment failures, accidents or other incidents that impact our ability to provide safe and reliable service to our customers.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers. Equipment or system failures could result in a disruption of service to our customers. We are also exposed to the risk of accidents or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims and increase the level of oversight at our facilities through investigations or through the imposition of additional regulatory or legislative requirements.

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Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets of terrorist activity, which could impact operations and result in increased capital, insurance and operating costs, including increased security costs for our facilities.

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 through rates. 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.

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Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

We have a $1.3 billion investment in leveraged leases, primarily generating stations in the United States. Although all payments of equity rent, debt service and other fees are current, no assurances can be given that all payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default we could be required to make an additional investment or potentially impair our current investment balances.

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.

The IRS has issued reports with respect to its audits of PSEG s consolidated 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.

As of December 31, 2010, an aggregate of approximately $260 million would become currently payable if PSEG conceded all deductions taken through that date. We have deposited $320 million with the IRS to defray potential interest costs associated with this disputed tax liability, eliminating our cash exposure completely. Penalties of $150 million would also become payable if the IRS successfully asserted and litigated a case against us. Interest and penalty exposure will grow at an average rate of $2 million per quarter during 2011. 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 $20 million to $40 million of tax would be due for tax positions through December 31, 2010.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, Power and PSE&G

None.

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 13. Commitments and Contingent Liabilities.

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Generation Facilities

As of December 31, 2010, Power s share of summer installed generating capacity was 13,538 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	632	100%	632	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	514	100%	514	Coal/Oil	Base Load/Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**6,399**		**3,753**		
Nuclear:						
Hope Creek	NJ	1,197	100%	1,197	Nuclear	Base Load
Salem 1 & 2	NJ	2,337	57%	1,342	Nuclear	Base Load
Peach Bottom 2 & 3(B)	PA	2,245	50%	1,122	Nuclear	Base Load
Total Nuclear		**5,779**		**3,661**		
Combined Cycle(C):						
Bergen	NJ	1,178	100%	1,178	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	755	100%	755	Gas	Load Following
Total Combined Cycle		**3,163**		**3,163**		
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	557	100%	557	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	17	100%	17	Oil	Peaking
Total Combustion Turbine		**2,777**		**2,761**		
Pumped Storage:						
Yards Creek(D)	NJ	400	50%	200		Peaking
Total Operating Power Plants		**18,518**		**13,538**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation

(C) The above table excludes our two Texas plants with an aggregated owned capacity of 2,000 MW as we reached agreements to sell these facilities in January 2011, in separate transactions, and anticipate closing the sales by the second quarter of 2011.

(D) Operated by Jersey Central Power and Light Company

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As of December 31, 2010 PSE&G had 28 MW of installed solar capacity as shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Principal Fuels Used
New Jersey				
Pole-Attached Units (72,000)	Statewide	15	100%	Solar
Yardville Solar Farm	Hamilton	1	100%	Solar
Linden Solar Farm	Linden	3	100%	Solar
Silver Lake Solar Farm	Edison	2	100%	Solar
Trenton Solar Farm	Trenton	1	100%	Solar
Newark Public Schools(4)	Newark	2	100%	Solar
PSE&G Edison Traning Center	Edison	1	100%	Solar
PSE&G Central Division HQ	Somerset	1	100%	Solar
WEA Roof Solar	Bayonne	2	100%	Solar
Total Operating Power Plants		**28**		

Energy Holdings had investments in the following generation facilities as of December 31, 2010:

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
Bridgewater	NH	16	40%	6	Biomass
Conemaugh	PA	15	4%	1	Hydro
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Total United States		**400**		**206**	
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		**560**		**270**	

Transmission and Distribution Facilities

As of December 31, 2010, PSE&G s electric transmission and distribution system included 23,566 circuit miles, of which 8,398 circuit miles were underground, and 828,786 poles, of which 545,377 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2010, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

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As of December 31, 2010, 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**

As of December 31, 2010, PSE&G owned and operated 17,608 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, 2010, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 23,543 megavolt-amperes and 246 substations with an aggregate installed capacity of 8,179 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 13. Commitments and Contingent Liabilities.

LCAPP

In January 2011, New Jersey enacted LCAPP which provides for the construction of 2,000 megawatts of subsidized baseload or mid-merit electric power generation. In February 2011, we joined other plaintiffs in an action filed in the United States District Court for the District of New Jersey challenging the constitutionality of LCAPP under the Supremacy and Commerce clauses of the United States Constitution. The complaint seeks declaratory and injunctive relief. Also in February 2011, PSEG and a group of other generators filed a complaint asking FERC to take steps to mitigate the impact of this subsidized generation on the capacity markets.

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Electric Discount and Energy Competition Act (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.

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. In June 2010, the BPU granted PSE&G s motion to dismiss. PSE&G has not yet received the written order from the BPU memorializing its decision.

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. On September 16, 2010, FERC approved a settlement agreement entered into by PSE&G, Con Ed, PJM, NYISO and others. This settlement provides the basis for moving forward with Con Ed after the current contracts expire in 2012 and settles all issues associated with the existing contracts, including cases pending in the D.C. Circuit Court of Appeals. However, dismissal of these court cases is contingent upon receipt of a final, non-appealable order from the FERC. One party to the proceeding has sought rehearing of the FERC approval order and will likely appeal an adverse decision on rehearing. As a result, the settlement has not yet taken effect and may not take effect for some time.

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.

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(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 presented the design details of the EPA s selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2013 at an estimated cost of $1 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. Anticipated future activities at the site include the filing of certification(s) with NJDEP once every two years regarding the effectiveness of engineering and institutional controls, quarterly groundwater monitoring for several years and the installation of additional off-site groundwater monitoring wells as directed by NJDEP.

(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. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent to conduct the RI/FS.

(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 13. 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.

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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, 2010, there were 81,659 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2005 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.

	2005	2006	2007	2008	2009	2010
PSEG	$ 100.00	$ 105.84	$ 160.80	$ 98.97	$ 117.63	$ 117.53
S&P 500	$ 100.00	$ 115.76	$ 122.11	$ 77.00	$ 97.31	$ 111.95
DJ Utilities	$ 100.00	$ 116.64	$ 140.04	$ 101.13	$ 113.69	$ 121.02
S&P Electrics	$ 100.00	$ 123.15	$ 151.57	$ 112.47	$ 116.23	$ 120.21

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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
2010			
First Quarter	$ 33.75	$ 29.01	$ 0.3425
Second Quarter	$ 34.21	$ 29.02	$ 0.3425
Third Quarter	$ 34.93	$ 30.92	$ 0.3425
Fourth Quarter	$ 33.97	$ 30.35	$ 0.3425
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

On February 15, 2011, our Board of Directors approved a $0.3425 per share of common stock dividend for the first quarter of 2011. This reflects an indicated annual dividend rate of $1.37 per share.

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation award grants during the fourth quarter of 2010:

Three Months Ended December 31, 2010	Total Number of Shares Purchased(A)	Average Price Paid per Share
October 1-October 31	0	N/A
November 1-November 30	11,000	$ 30.91
December 1-December 31	5,600	$ 31.30

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2010:

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	3,660,634	$ 32.22	17,930,109(A)
Equity compensation plans not approved by security holders	0	$ 0.00	3,589,032(B)

Total	**3,660,634**	**$ 32.22**	**21,519,141**

(A) Shares issuable under our Long-Term Incentive Plan (LTIP).
(B) Shares issuable under our Employee Stock Purchase Plan.

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data Note 18. 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 2010 and Future Outlook.

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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 2010 and Future Outlook.

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

	2010	2009	2008	2007	2006
For the Years Ended December 31:	Millions, where applicable				
Operating Revenues	$ 11,793	$ 12,035	$ 12,609	$ 12,051	$ 11,061
Income from Continuing Operations(A)	$ 1,557	$ 1,594	$ 918	$ 1,274	$ 588
Net Income	$ 1,564	$ 1,592	$ 1,188	$ 1,335	$ 739
Earnings per Share:					
Income from Continuing Operations:					
Basic(A)	$ 3.08	$ 3.15	$ 1.81	$ 2.51	$ 1.17
Diluted(A)	$ 3.07	$ 3.14	$ 1.81	$ 2.50	$ 1.16
Net Income:					
Basic	$ 3.09	$ 3.15	$ 2.34	$ 2.63	$ 1.47
Diluted	$ 3.08	$ 3.14	$ 2.34	$ 2.62	$ 1.46
Dividends Declared per Share	$ 1.37	$ 1.33	$ 1.29	$ 1.17	$ 1.14
As of December 31:					
Total Assets	$ 29,909	$ 28,678	$ 29,049	$ 28,299	$ 28,508
Long-Term Obligations(B)	$ 7,847	$ 7,679	$ 8,044	$ 8,709	$ 10,147

(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 Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (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 LLC (Energy Holdings),** which owns lease 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. Our risk factor discussion in Item 1A. provides information about factors that could have a material adverse impact in our businesses. The following discussion expands upon those sections by describing significant events and business developments that have occurred during 2010 and key factors that we expect 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 discussion should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2010 AND FUTURE OUTLOOK

During 2010, our business continued to face many of the same challenges experienced in 2009. Lower natural gas prices and current economic conditions have had an adverse impact on our results.

The market price for electricity is based upon the cost of generation at the margin. In the eastern part of PJM, the marginal generating unit is usually fueled by natural gas. As a result, the sustained decline in natural gas pricing that we have been experiencing has significantly reduced the gross margin we are able to realize on sales from our units in the eastern part of PJM, as nuclear and coal fuel costs have not declined similarly. Our practice of selling a substantial portion of our electricity production in forward transactions has limited the impact of lower wholesale electricity prices on our 2010 results, as much of the electricity that we produced in 2010 was sold at the higher forward market prices that prevailed in 2007 through 2009. We expect that, as these pre-2010 transactions are closed, the lower energy prices that now prevail will have a more significant adverse impact on our results for 2011 and 2012. Our results for 2011 and 2012 will also be impacted by lower capacity pricing set through the Reliability Pricing Model (RPM) auctions as compared to 2010 prices.

Economic conditions and other governmental policy initiatives have resulted in increased conservation efforts by residential customers and have also caused some continued erosion in our commercial and industrial customer base. This has contributed to lower demand for electricity, which also tends to reduce congestion, thereby reducing the hours that higher priced units in the eastern part of PJM are called to operate. These factors have put additional downward pressure on Power s revenues. Economic conditions also put downward pressure on delivered volumes and fixed demand revenues from commercial and industrial customers at PSE&G. For both businesses in 2010, the impact on electric volumes caused by economic conditions and pricing was offset to a significant degree by the impact of weather which resulted in higher demand for energy during the third quarter.

Lower market prices for electricity also tend to create a greater incentive for customers to choose an alternate electric supplier rather than receive electricity from Power under our Basic Generation Service (BGS) contracts, as the current market prices are lower than the BGS contract energy price components which were set when forward prices were higher. We experienced an increasing level of this migration away from BGS

contracts beginning toward the second half of 2009 which continued into 2010. The rate of migration may also increase as certain third party suppliers have started to offer additional incentives for customers to switch to an alternate electric supplier. This customer migration trend could continue in any period where current market prices are below the average BGS rates in effect at the time. This may have a material impact on our financial results by accelerating the impact of declining market prices on Power s results as sales at BGS rates, which are reset gradually with prices set for only one-third of the anticipated load through the BGS auction each year, are replaced by lower priced market sales.

In an effort to mitigate some of these impacts, Power has entered into additional sales contracts with third parties and increased sales in the spot market. We also requested that the New Jersey Board of Public Utilities (BPU) hold a stakeholder proceeding and collect additional data to evaluate unintended adverse consequences of increased switching activity, with the objective of appropriately allocating risks between BGS suppliers and third party suppliers in future BGS auctions. In an order issued in December 2010 as part of its annual BGS review, the BPU indicated that it would continue to examine future switching activity and take action as it deems may be necessary in the future. No assurances can be given that our efforts to offset any adverse impacts will be successful.

Our gas sales volumes were also lower in 2010 due primarily to warmer winter weather early in the year. Heating degree days, as a measure of winter weather in 2010, were 6% lower than in 2009. The weather, the economy and other factors all contributed to an overall reduction of approximately 4% in Power s Basic Gas Supply Service (BGSS) sales volumes and PSE&G s gas delivery volumes as compared to 2009.

In June 2010, the BPU accepted and approved a settlement agreement reached by the parties to our base rate case proceeding. The final settlement agreement included an increase of $73.5 million and $26.5 million in annual electric and gas revenues, respectively, with a return on equity (ROE) of 10.3%. The new rates and rate designs were effective on June 7, 2010 for the electric portion and July 9, 2010 for gas. The BPU also approved PSE&G s gas weather normalization clause.

Also in June 2010, the BPU approved an agreement under which PSE&G will refund $122 million to electric customers during the next two years to resolve an issue regarding the Market Transition Charge (MTC) which was part of New Jersey s deregulation law implemented in 1999. For additional information, see Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities.

As part of the gas base rate proceeding, the BPU ordered a supplemental and expedited review of certain issues related to the gas transportation rate that PSE&G charges to Power. The BPU provisionally approved the stipulated Transportation Service Gas Nonfirm (TSG-NF) rate subject to refund pending the outcome of this review. In July 2010, a complaint was filed against Power at the Federal Energy Regulatory Commission (FERC) related to the gas transportation rate. On December 16, 2010, the BPU approved a settlement that resolves these issues, and the FERC complaint has been withdrawn. Under the settlement, there will be no retroactive adjustments or refunds made by PSE&G with respect to the gas delivery charges. For additional information, see Item 1. Business State Regulation.

We currently have FERC-approved formula rates in effect to recover the costs related to our existing and future transmission investments. 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 annual costs and capital expenditures and an approved base return on equity (ROE) of 11.68% for our transmission investments once the facilities are placed in service. We have received incentive ROE rates of 12.93% for our Susquehanna-Roseland line, including an immediate return on the Construction Work in Progress (CWIP) dollars spent on these projects. Our 2010 transmission rates which became effective on January 1 provided for approximately $23 million in increased annual revenues as compared to 2009. We filed our 2011 Annual Formula Rate Update with FERC in October 2010, which will provide approximately $45 million in increased annual revenues in 2011 transmission rates effective January 1, 2011.

Whether FERC will continue to authorize incentive rates for new transmission projects, including ROE adders, CWIP and abandonment cost recovery, to the same extent that it has over the last several years is uncertain. FERC has issued several incentive rate orders that either set the rates for hearing or denied the requested

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incentives finding that the applicants failed to sufficiently demonstrate that the projects justified incentive rate treatment. In December 2010, FERC denied PSE&G s request for CWIP and 100% abandonment cost recovery for four baseline Regional Transmission Expansion Planning (RTEP) projects. FERC s December order provides that PSE&G may re-file its request for incentive rates and demonstrate that each project satisfies FERC s test for incentive rates individually, rather than on an aggregate basis. PSE&G is currently considering this option.

There have also been other significant regulatory and legislative developments during the year which may affect our operations in the future as new rules and regulations are adopted. For additional information on these issues, see Item 1. Business Regulatory Issues and Environmental Matters.

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 were signed into law. This new legislation includes various health care related provisions that will go into effect over the next several years. This legislation eliminates the tax deductibility of retiree health care costs, to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, which resulted in additional deferred tax liabilities being recorded in the first quarter. For additional information, see Item 8. Financial Statements and Supplementary Data -Note 20. Income Taxes. In October 2010, we made various changes to our active employee medical programs, generally effective January 1, 2011, to comply with the new requirements. For our retiree health care programs, we have contracted with a group Prescription Drug Plan, effective January 1, 2013, for coordination of the government-provided Retiree Drug Subsidy. We also applied, and have been approved for funds under the Early Retiree Reinsurance Program. We will evaluate any additional guidance on this legislation as it becomes available. To help mitigate the effect of the increasing health care costs, we are changing our pre-65 and post-65 retiree prescription drug formularies to an incentive design for the majority of retirees, to be phased in over a three year period beginning January 1, 2011.

In May 2010, the U.S. Environmental Protection Agency (EPA) finalized a Tailoring Rule that will phase in Clean Air Act permitting requirements beginning in 2011 for major facility modifications that increase the emission of greenhouse gases (GHGs), including carbon dioxide (CO_2), at facilities such as ours. The significance of the permitting requirement is that, in cases where a new source is constructed or an existing source undergoes a major modification, the owner of the facility would need to evaluate and perhaps install best available control technology (BACT) for GHG emissions. In December 2010, the EPA announced a schedule to proposed New Source Performance Standards (NSPS) for GHGs from power plants and refineries. The NSPS applies to both the construction of new sources as well as the modification of existing sources. Since a proposed rule has not been published, the outcome of the rulemaking and its significance to the company cannot be predicted.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was passed in an attempt to reduce systemic risk in the financial markets thereby preventing future financial crises and market issues such as those experienced recently. As part of this new legislation, the SEC and the Commodity Futures Trading Commission (CFTC) will be implementing new rules to enact stricter regulation over swaps and derivatives since many of the issues experienced were caused by derivative trading in connection with mortgage loans. CFTC has issued Notices of Proposed Rulemakings (NOPRs) on many of the key issues. Although the Dodd-Frank Act specifically recognizes a commercial end user exemption from posting additional collateral in the bilateral Over the Counter swap and derivative markets, we cannot assess the exact scope of the new rules until the SEC and CFTC issue them. Under the current NOPRs, the broad definition of swap dealer could result in us being classified as a dealer, which would limit the benefits of the commercial end-user exemption recognized in the Act.

Another new issue has arisen in the context of a pending FERC rulemaking proceeding, in which FERC has proposed to significantly change its transmission planning rules to (i) make it easier to plan transmission for public policy considerations and (ii) open up the construction of transmission projects to companies that are not franchised utilities or that seek to build outside of their franchised service territory. We are actively participating in this proceeding.

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In June 2010, the EPA formally published a proposed rule offering three main options for the management of coal combustion residuals to limit impacts on human health and the environment. The outcome of the EPA rulemaking cannot be predicted.

In August 2010, the EPA proposed the Clean Air Transport Rule (CATR) to limit emissions in 32 states that contribute to the ability of downwind states to attain and/or maintain air quality standards. The CATR is scheduled to be effective January 1, 2012, with further reductions in emissions as part of a second phase effective January 1, 2014. By 2014, the EPA estimates that this rule, along with other concurrent state and EPA actions, would reduce power plant sulfur dioxide (SO_2) emissions by 71% and nitrogen oxide (NO_X) emissions by 52% as compared to 2005 levels. In October 2010, we submitted comments generally supporting the EPA s proposal. We would expect the final implementation of this rule to be beneficial to us based on our generation mix and our investment in emissions controls; however, no assurances can be given.

During the second quarter, the Governor of New Jersey directed the BPU to review the State s current Energy Master Plan (EMP). The current EMP was issued in October 2008 and identified a number of actions to improve energy efficiency, increase the use of renewable resources, ensure a reliable supply of energy and stimulate investment in clean energy technologies. We expect the BPU to release a new draft EMP by the first quarter of 2011 with a final plan expected to be completed later next year. We cannot predict what modifications or new goals will be included in the new EMP or the potential impacts to our businesses.

On January 28, 2011, New Jersey enacted the long-term capacity agreement pilot program (LCAPP) which provides for 2,000 megawatts of subsidized baseload or mid-merit electric power generation. This may have the effect of artificially depressing prices in the competitive wholesale market and thus has the potential to harm competitive markets, on both a short-term and a long-term basis, if implemented as currently contemplated by the State of New Jersey. Construction of new subsidized local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints. The LCAPP legislation is being challenged both at FERC and in court. Specifically, in February, PSEG and a group of other generators filed a complaint at the FERC seeking to prevent the subsidized generation from interfering with the wholesale capacity market and a case in federal district court arguing that the legislation is unconstitutional and should be invalidated. Both actions are pending.

Looking ahead, the key issues our business will confront are:

- continued downward pressure on natural gas and electricity prices,
- a slow economy,
- regulatory and political uncertainty, particularly around environmental regulation, and
- pressure on competitive markets in many states, including New Jersey.

Our future success will also depend on our ability to respond to these challenges and take advantage of opportunities presented by these and other regulatory and legislative initiatives. In order to do this, we must:

- focus on controlling costs while maintaining operational excellence,
- successfully recontract open positions, and

execute our capital investment program, including continued investments for growth that yield contemporaneous returns.

Operational Excellence

Generation volumes at Power in 2010 were approximately 9% higher than in 2009, primarily at our combined cycle and coal facilities, to meet increased demands due to hotter weather. Our ability to meet the increased weather-related demands through the strong operations of our generation fleet helped to offset the impacts of migration and reduced market prices for electricity.

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Our generating capacity continues to receive pricing recognizing the locational value of our assets through the RPM auction. Under the most recent auction for the 2013-2014 period, the prices set for our generation assets in PJM were $245 per MW-day for the Eastern MAAC and PSEG North zones and $226.15 per MW-day for the MAAC zone. These prices were higher than prices set for previous periods.

During 2010, PSE&G has continued to demonstrate its commitment to system reliability by limiting customer outages. However, in mid-March, PSE&G experienced the worst storm in its history. The storm caused severe damage to our system downing more than 1,000 poles throughout our service territory and disrupting service to over 600,000 customers. With the assistance of mutual aid crews from other utilities, PSE&G s associates worked to fully restore service to all of its customers within one week. PSE&G has deferred the incremental storm related costs and will be seeking recovery.

We have also maintained our focus on reducing 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. As of the end of 2010, we have terminated our entire portfolio of international leases and reduced the related cash tax exposure by $1.1 billion. As of December 31, 2010, an aggregate of approximately $260 million would become currently payable if we conceded all deductions taken through that date. We have deposited $320 million with the IRS to defray potential interest costs associated with this disputed tax liability, eliminating our cash exposure completely. See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for additional information.

We continue to look for ways to reduce our operating costs at each of our businesses while maintaining our safety, reliability and compliance standards.

Financial Strength

Our businesses had strong cash from operations in 2010 which was used to contribute over $400 million into our qualified pension plans, fund our capital expenditures and fund our shareholder dividends. We also completed several financing transactions during 2010, including paying our maturing debt obligations, redeeming PSE&G s preferred stock and completing a debt exchange at Power to manage long-term debt maturities. See Item 8. Financial Statements and Supplementary Data -Note 14. Schedule of Consolidated Debt for additional information.

While we anticipate earnings to be lower in 2011, our cash from operations is expected to remain strong. In addition, two tax provisions enacted in 2010 are expected to generate approximately $750 million of cash benefits for us through accelerated depreciation, most of which is expected to be realized in 2011. See Item 8. Financial Statements and Supplementary Data Note 20. Income Taxes for additional information. These funds will be used to support our anticipated capital expenditures in 2011 and fund pension plan contributions and dividend payment amounts similar to those paid in 2010.

Disciplined Investment

We seek to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include responding to trends in environmental protection, 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.

We are continuing to pursue obtaining the necessary regulatory approvals for the Susquehanna-Roseland transmission project but have incurred delays in obtaining environmental approvals. The failure to obtain these approvals on a timely basis has delayed the project implementation date. The estimated cost of construction is up to $750 million for this project. In October, the PJM Board approved a modified Branchburg to Hudson project, specifically a 230 kV project running from Roseland to Hudson. The Roseland to Hudson project has an expected in-service date of June 2015. The estimated cost of construction is up to $700 million for this project. Delays in the construction schedules of these projects could impact the timing of expected transmission revenues. For additional information, see Part I, Item 1. Business State Regulation.

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Our utility has made additional investments in solar initiatives. Under our solar loan program we have provided a total of $70 million in loans for 196 projects as of December 31, 2010, representing over 19 MW to date. Under our Solar 4 All program we have had total expenditures of over $200 million as of December 31, 2010. Over 15 MW of solar panels have been installed on distribution poles and another 13 MW representing 11 projects have been placed into service. Additional projects are in various stages of negotiation and development. Our total anticipated expenditures to develop all 80 MW approved is approximately $465 million. See Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities for additional information.

We made additional expenditures under our Capital Economic Stimulus and Energy Efficiency Economic Stimulus programs. As of December 31, 2010, total expenditures since inception of these projects were $588 million and $108 million, respectively. For additional information on these programs, see Item 1. Business State Regulation.

We continued various construction activities at Power, including the completion of installation of back end technology at our Mercer and Hudson stations, a steam path retrofit and extended power uprate at Peach Bottom and construction of new gas fired peaking units at Kearny and in Connecticut (see Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for additional information). This additional capacity at Kearny was bid into and has cleared the RPM capacity auction, and the additional capacity in Connecticut is subject to a contract with a Connecticut utility.

We filed an application for an Early Site Permit for a new nuclear generating station to be located at the current site of the Salem and Hope Creek generating stations and are continuing to pursue 20-year license extensions for our Salem and Hope Creek facilities.

Our solar projects in Ohio and Florida have commenced operations. The two projects total 27 MW. (See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for additional information).

There is no guarantee that the projects described above or any future initiatives will be achieved since many issues need to be favorably resolved, such as regulatory approvals.

In January 2011, we reached agreement to sell our two 1,000 MW combined-cycle generation facilities in Texas in separate transactions for a total of approximately $687 million. These transactions are expected to be closed in the first half of 2011.

RESULTS OF OPERATIONS

	Years Ended December 31,		
Earnings (Losses) In Millions	**2010**	**2009**	**2008**
Power	$ 1,136	$ 1,191	$ 1,050
PSE&G	359	325	364
Energy Holdings (A)	49	72	(468)
Other (B)	13	6	(28)
PSEG Income from Continuing Operations	**1,557**	**1,594**	**918**
Income (Loss) from Discontinued Operations, Including Gain on Disposal (C)	7	(2)	270
PSEG Net Income	**$ 1,564**	**$ 1,592**	**$ 1,188**

	Years Ended December 31,		
Earnings Per Share (Diluted)	**2010**	**2009**	**2008**
PSEG Income from Continuing Operations	**$ 3.07**	**$ 3.14**	**$ 1.81**
Income (Loss) from Discontinued Operations, Including Gain on Disposal (C)	0.01	0.00	0.53

PSEG Net Income	**$ 3.08**	**$ 3.14**	**$ 2.34**

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(A) Energy Holdings results include after-tax charges of $490 million taken in 2008 related to leveraged lease transactions and the reversal of $29 million, after-tax, of that reserve in 2009.

(B) Other includes parent company interest and financing costs, donations, certain administrative and general expenses and certain consolidating entries related to the debt exchange in 2009 between Power and Energy Holdings.

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

Our results include the realized gains, losses and earnings on Power s Nuclear Decommissioning Trust (NDT) Funds and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Funds which are recorded in Other Income and Deductions. This also includes credit-related impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power s nuclear asset retirement obligation (ARO), which is recorded in Operation and Maintenance Expense and the Depreciation expense related to the ARO. The combined after-tax impact on earnings of this activity for the years ended December 31, 2010, 2009 and 2008 is shown in the chart below along with the after-tax impacts of mark-to-market (MTM) activity:

		In Millions, after tax	
Years Ended December 31,	**2010**	**2009**	**2008**
NDT Fund Income (Expense) and Related Activity	$ 46	$ 9	$ (71)
Non-Trading MTM Gains (Losses)	$ (1)	$ (11)	$ 14

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, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data Note 23. Related-Party Transactions.

	For the Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2010	**2009**	**2008**	**2010 vs 2009**		**2009 vs 2008**	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 11,793	$ 12,035	$ 12,609	$ (242)	(2)	$ (574)	(5)
Energy Costs	5,261	5,433	6,800	(172)	(3)	(1,367)	(20)
Operation and Maintenance	2,504	2,534	2,414	(30)	(1)	120	5
Depreciation and Amortization	955	819	775	136	17	44	6
Income from Equity Method Investments	4	17	10	(13)	(76)	7	70
Other Income and (Deductions)	158	85	98	73	86	(13)	(13)
Other-Than-Temporary Impairments	11	61	220	(50)	(82)	(159)	(72)
Interest Expense	472	521	566	(49)	(9)	(45)	(8)
Income Tax Expense	1,059	1,042	888	17	2	154	17
Income (Loss) from Discontinued Operations, including Gain on Disposal in 2008, net of tax	7	(2)	270	9	N/A	(272)	N/A

The 2010 year-over-year decrease in our Income from Continuing Operations was driven by the following:

higher priced sales under our BGS contracts being replaced with comparatively lower priced sales into the various power pools and under new wholesale contracts entered into during 2010 as customer migration levels have increased,

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- losses on certain wholesale electric energy supply contracts,

- a $122 million charge recorded in June related to our agreement to refund previous Market Transition Charge (MTC) collections during the next two years,

- lower gas sales volumes and pricing due to milder winter weather and economic conditions, and

- lower gains on lease sales,

- partially offset by higher electric sales volumes and market pricing due primarily to warmer summer weather,

- higher electric delivery revenues due to our base rate increase approved in June,

- lower interest expenses, and

- realized gains related to the restructuring of the investments in our Rabbi Trusts.

The 2009 year-over-year increase in our Income from Continuing Operations was driven by the following:

- the 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.

- higher prices realized under sales contracts and lower generation costs, partially offset by lower sales volumes,

- gains on sales and terminations of leveraged lease assets, partially offset by lower income due to assets sold,

- lower other-than-temporary impairments on investments in the NDT Funds, and

- lower interest expenses,

- partially offset by 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

	For the Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2010	**2009**	**2008**	**2010 vs 2009**	**2009 vs 2008**
			Millions		
Income from Continuing Operations	$ 1,136	$ 1,191	$ 1,050	$ (55)	$ 141
Income (Loss) from Discontinued Operations, net of tax	7	(2)	65	9	(67)
Net Income	$ 1,143	$ 1,189	$ 1,115	$ (46)	$ 74

For the year ended December 31, 2010, the primary reasons for the decrease in Income from Continuing Operations were

higher priced sales under our BGS contracts being replaced with comparatively lower priced sales into the various power pools and under new wholesale contracts entered into during 2010 as customer migration levels have increased,

losses on certain wholesale electric energy supply contracts and

lower gas sales volumes and pricing due to more moderate winter weather in 2010 and economic conditions,

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partially offset by favorable amounts related to our NDT and MTM activity discussed previously,

higher volumes of generation sold at higher market prices in PJM due to warmer summer weather, and

realized gains on the investments in our Rabbi Trust.

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.

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	**2010**	**2009**	**2008**	**2010 vs 2009**		**2009 vs 2008**	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 6,558	$ 6,772	$ 7,770	$ (214)	(3)	$ (998)	(13)
Energy Costs	3,374	3,462	4,556	(88)	(3)	(1,094)	(24)
Operation and Maintenance	1,046	1,045	1,054	1	0	(9)	(1)
Depreciation and Amortization	175	184	164	(9)	(5)	20	12
Other Income (Deductions)	117	98	98	19	19	0	0
Other-Than-Temporary Impairments	9	60	219	(51)	(85)	(159)	(73)
Interest Expense	157	161	164	(4)	(2)	(3)	(2)
Income Tax Expense	778	767	661	11	1	106	16
Income (Loss) from Discontinued Operations	7	(2)	65	9	N/A	(67)	N/A

For the year ended December 31, 2010 as compared to 2009

Operating Revenues decreased $214 million due to

Gas Supply Revenues decreased $296 million

- including a net decrease of $304 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2010 as well as lower net gains on financial hedging transactions in 2010,
- partially offset by a net increase of $8 million due to higher average gas prices on reduced sales volumes to third party customers.

Trading Revenues decreased $86 million due primarily to net losses on certain electric energy supply contracts in 2010 partly offset by losses on certain gas supply contracts realized in 2009 that expired in December 2009.

Generation Revenues increased $168 million due primarily to

- higher net revenues of $161 million resulting from higher volumes of generation sold at higher prices in PJM and the NY power pool, partially offset by less favorable results from financial hedging transactions and lower revenues in the NE power pool,
- an increase of $166 million from new wholesale load contracts in PJM commencing in 2010,

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$38 million of increased revenues from operating reserves in the PJM and NE regions and various ancillary services, and $20 million of higher capacity payments largely due to changes in PJM s capacity market,

partially offset by a net decrease of $184 million due to a lower volume of electricity sold at lower average prices under our BGS contracts, reflecting customer migration to alternative suppliers and warmer winter temperatures in 2010, and

a decrease of $30 million in auction revenue rights reflecting lower rates and migration of PJM customers in 2010.

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 $88 million due to

Gas costs decreased $294 million, principally related to Power s obligations under the BGSS contract, reflecting lower average gas inventory costs and lower demand.

Generation costs increased by $206 million due primarily to $287 million of higher fossil fuel costs, primarily reflecting the utilization of higher volumes of both coal and natural gas, $45 million of higher net purchases in PJM, $15 million of higher nuclear fuel costs due to higher prices, and an $18 million impairment charge in 2010 related to forecasted excess SO_2 emissions allowances. These increases were partly offset by higher net gains of $79 million from financial hedging transactions, $40 million of lower congestion charges incurred in 2010 from PJM, $28 million of lower purchases of firm transmission rights in 2010 and a decrease of $15 million of energy purchases in the NE power pool driven by reduced load obligations resulting from the expiration of certain contracts in 2010.

Operation and Maintenance experienced no material change.

Depreciation and Amortization decreased $9 million due primarily to

a $19 million decrease due to an extension of the remaining useful lives of the Mercer and Hudson generating facilities resulting from significant plant upgrades as well as revisions in assumptions regarding the decommissioning of our plants,

partially offset by an increase of $7 million due to pollution control equipment being placed into service in October 2009 at our Keystone station, and

an increase of $4 million due to a reversal of depreciation expense in September 2009 related to the reimbursement of previously capitalized storage costs for spent nuclear fuel resulting from a favorable settlement for such costs by the U.S. Department of Energy (DOE).

Other Income and (Deductions) The net increase of $19 million was due primarily to

$10 million of lower purchases of New Jersey net operating losses related to the state corporate business tax,

a $7 million gain realized on the investments in our Rabbi Trust, and a $4 million increase in net earnings related to our NDT Fund.

Other-Than-Temporary Impairments decreased $51 million due to the lower charges in 2010 related to certain NDT Fund securities.

Interest Expense decreased $4 million due to

higher capitalized interest of $21 million due primarily to an increased level of projects under construction in 2010,

partially offset by higher net interest costs of $15 million related to higher interest and debt issuance costs related to $303 million of Senior Notes issued in September 2009 as part of a debt exchange with Energy Holdings, partly offset by the effects of the early redemption of two medium-term note obligations and a note exchange that all occurred in April 2010, and an increase of $2 million in credit facility fees.

Income Tax Expense increased $11 million in 2010 due primarily to

an increase of $18 million due to lower manufacturer s deductions under the American Jobs Creation Act of 2004, primarily caused by lower taxable income due to increased bonus depreciation allowed by the passage in 2010 of tax law changes,

an increase of $8 million due to the impacts of new health care legislation (see Item 8. Financial Statements and Supplementary Data -Note 20. Income Taxes), and

a net increase of $3 million related to prior year adjustments, state taxes, the NDT Funds and other miscellaneous adjustments,

partially offset by a decrease of $18 million due to lower pre-tax income.

Income (Loss) from Discontinued Operations

In January 2011, Power reached an agreement to sell its Guadalupe and Odessa power plants in Texas. The plants will be sold in two separate transactions which are expected to be closed in the first half of 2011. Accordingly, Power s Income from Continuing Operations for 2010 and 2009 was retroactively adjusted by the after-tax results of operations of these plants. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations and Dispositions for additional information.

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

Operating Revenues decreased $998 million due to

Generation Revenues decreased $391 million due primarily to

lower revenues of $272 million resulting from lower volumes of generation sold at lower prices in PJM and the NY power pool and lower prices on a higher volume of generation sold in the NE power pool, 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 $1,094 million due to

Generation costs decreased by $479 million due primarily to $735 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 $181 million related to Power s obligations under the BGSS contract and sales to third party customers respectively, reflecting lower inventory costs.

Operation and Maintenance decreased $9 million due primarily to

a net decrease of $83 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 $20 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

an increase of $8 million resulting from larger depreciable asset bases for fossil and nuclear in 2009,

partially offset by a $4 million reversal of depreciation expense 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 DOE.

Other Income and (Deductions) reflected no change due primarily to

a net increase of $6 million in net earnings related to the NDT Funds,

principally offset by a write-off of $5 million due to the early retirement of obsolete pollution control equipment.

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

Interest Expense decreased $3 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 $7 million due to the maturity of $250 million of 3.75% Notes in April 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 $106 million in 2009 due primarily to

an increase of $96 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.

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Income (Loss) from Discontinued Operations

In January 2011, Power reached an agreement to sell its Guadalupe and Odessa power plants in Texas. The plants will be sold in two separate transactions which are expected to be closed in the first half of 2011. Accordingly, Power s Income from Continuing Operations for 2009 and 2008 was retroactively adjusted by the after-tax results of operations of these plants.

See Item 8. Financial Statements and Supplementary Data -Note 4. Discontinued Operations and Dispositions for additional information.

PSE&G

	For the Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2010	**2009**	**2008**	**2010 vs 2009**	**2009 vs 2008**
			Millions		
Income from Continuing Operations	$ 359	$ 325	$ 364	$ 34	$ (39)
Net Income	$ 359	$ 325	$ 364	$ 34	$ (39)

For the year ended December 31, 2010, the primary reasons for the increase in Income from Continuing Operations were

- higher base rates for electric and gas delivery as well as transmission,
- higher revenues from our Capital Economic Stimulus Infrastructure and Regional Greenhouse Gas Initiative (RGGI) programs, and
- higher electric delivery volume,
- partially offset by the $122 million charge related to our agreement to refund previous MTC collections, and
- lower gas sales volumes due to milder winter weather.

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 poor economic conditions, and
- higher Operation and Maintenance expense, primarily increased pension expense,
- partially offset by a transmission formula rate increase.

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

PSE&G	For the Years Ended December 31, 2010	2009	2008	Increase/ (Decrease) 2010 vs 2009		Increase/ (Decrease) 2009 vs 2008	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 7,869	$ 8,243	$ 9,038	$ (374)	(5)	$ (795)	(9)
Energy Costs	4,655	5,170	6,072	(515)	(10)	(902)	(15)
Operation and Maintenance	1,442	1,474	1,338	(32)	(2)	136	10
Depreciation and Amortization	750	608	583	142	23	25	4
Other Income and (Deductions)	23	5	8	18	360	(3)	(38)
Interest Expense	318	312	325	6	2	(13)	(4)
Income Tax Expense	232	226	228	6	3	(2)	(1)

For the year ended December 31, 2010 as compared to 2009

Operating Revenues decreased $374 million due primarily to

Commodity Revenue decreased $515 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.

- Gas revenues decreased $291 million due to decreased BGSS prices of $206 million and lower BGSS volumes of $85 million due to warmer weather and economic conditions. The average price of gas was 11% lower in 2010 than in 2009.

- Electric revenues decreased $224 million due primarily to $339 million in lower BGS revenues, partially offset by $115 million in higher revenues from the sale of Non-Utility Generation (NUG) energy and collections of non-utility generation charges (NGC) due primarily to higher prices. BGS sales were down 9% due primarily to large customer migration to third party suppliers (TPS); in contrast delivery sales were up 5% due to warmer weather.

Clause Revenues decreased by $45 million due primarily to the MTC refund of $122 million and the Gas Weather Normalization deferral of $9 million, which were partially offset by higher Securitization Transition Charge (STC) revenues of $86 million. The Electric Societal Benefit Charge (SBC) was $8 million higher, offset by lower Gas SBC of $8 million. The changes in STC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest. PSE&G earns no margins on SBC or STC collections.

Delivery Revenues increased $170 million due primarily to an increase in prices for electric and gas distribution and transmission.

- Electric distribution revenues were up $137 million due primarily to higher sales volumes of $54 million, the impact of the June base rate increases of $49 million, stimulus revenue increases of $17 million and RGGI revenue increases of $17 million.

- Transmission revenues were up $29 million due primarily to net rate increases.

- Gas distribution revenues were up $4 million due primarily to the impact of the July base rate increase of $8 million, capital stimulus revenue increase of $6 million and RGGI revenue increase of $5 million, partially offset by lower sales volumes of $15 million.

Other Operating Revenues increased $16 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Energy Costs decreased $515 million. This is entirely offset by Commodity Revenue. Details are as follows:

- Gas costs decreased $291 million due to $206 million or 11% in lower prices and by $85 million or 5% in lower sales volumes due primarily to warmer weather and economic conditions.

- Electric costs decreased $224 million due to $261 million or 8% in lower BGS and NUG volumes due to large customer migration to TPS and warmer weather, partially offset by $37 million of higher BGS and NUG prices.

Operation and Maintenance decreased $32 million due to a $54 million decrease in electric and gas operating expenses due primarily to our overall cost reduction efforts, and

a $12 million reduction in bad debt expense,

partially offset by a $14 million write-off of deferred costs associated with the new customer accounting system,

$11 million in storm restoration work, and

a net $9 million of higher expenses associated with SBC, STC, RGGI and Stimulus clauses.

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Depreciation and Amortization increased $142 million due primarily to

- an increase of $116 million for amortization of Regulatory Assets,
- an increase of $15 million for additional plant in service,
- a net increase of $6 million relating to various adjustments, and
- an increase of $5 million in software amortization.

Other Income and (Deductions) The net increase of $18 million was due primarily to $11 million of gains realized on the investments in our Rabbi Trust, a $5 million increase in Solar Loan interest income and a $5 million increase in capitalized allowance for Equity Funds used during construction, partially offset by $3 million of various other items.

Interest Expense increased by $6 million due primarily to new debt issued in 2010.

Income Tax Expense increased by $6 million due primarily to higher pre-tax income, partially offset by flow-through tax benefits primarily related to uncollectible accounts and other adjustments.

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

Operating Revenues decreased $795 million due primarily to

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 due primarily to $355 million in lower BGS revenues and $124 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales were down 14% due primarily to large customer migration to TPS; in contrast delivery sales were up 4% due to weather and economic conditions.
- Gas revenues decreased $423 million due to decreased BGSS prices of $365 million and lower BGSS volumes of $58 million due to economic conditions. The average price of gas was 16% lower in 2010 than 2009.

Clause Revenues increased by $67 million due primarily to higher electric and gas SBC of $69 million, partially offset by lower STC of $2 million. The changes in STC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC or STC collections.

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

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

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

Electric distribution revenues were down $23 million due primarily to lower sales volumes of $48 million, partially offset by RGGI revenue increases of $12 million, rate increases of $8 million and stimulus revenue increases of $5 million. The volumes were down due to weather and economic conditions. The economic slowdown reduced volumes as customers cut back on use of air conditioning to save money.

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

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

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 partially offset by $8 million in higher BGS and NUG prices.

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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.

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) The decrease of $3 million was due to $4 million in lower investment income resulting from current market conditions, partially offset by $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 pre-tax income, offset by $17 million of tax benefits taken in 2008 related to an IRS refund.

Energy Holdings

	For the Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2010	**2009**	**2008**	**2010 vs 2009**	**2009 vs 2008**
			Millions		
Income (Loss) from Continuing Operations	$ 49	$ 72	$ (468)	$ (23)	$ 540
Income from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	0	0	205	0	(205)
Net Income (Loss)	$ 49	$ 72	$ (263)	$ (23)	$ 335

For the year ended December 31, 2010, the primary reasons for the decrease in Income from Continuing Operations were

- lower gains on the sales of leveraged lease assets, and asset impairment charges (see Item 8. Financial Statements and Supplementary Data -Note 17. Fair Value Measurements),

partially offset by a gain on the sale of real estate assets and the absence of the premium paid on the debt exchange with Power in 2009.

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.

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

Energy Holdings	For the Years Ended December 31, 2010	2009	2008	Increase/ (Decrease) 2010 vs 2009 Millions	%	Increase/ (Decrease) 2009 vs 2008 Millions	%
		Millions					
Operating Revenues	$ 137	$ 221	$ (368)	$ (84)	(38)	$ 589	N/A
Operation and Maintenance	42	47	57	(5)	(11)	(10)	(18)
Depreciation and Amortization	14	11	11	3	27	0	0
Income from Equity Method Investments	4	17	9	(13)	(76)	8	89
Other Income and (Deductions)	12	(27)	25	39	N/A	(52)	N/A
Interest Expense	11	37	57	(26)	(70)	(20)	(35)
Income Tax Expense	37	45	9	(8)	(18)	36	N/A
Income from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	0	0	205	0	0	$ (205)	(100)

For the year ended December 31, 2010 as compared to 2009

Operating Revenues decreased $84 million due primarily to lower gains on the sale and termination of leveraged lease assets and the resultant loss of revenues previously generated by such assets, partially offset by earnings from our solar projects which commenced operation in 2010.

Operation and Maintenance decreased $5 million due primarily to reduction of Services company charges and decreases in labor and outside service costs as part of our overall cost reduction efforts.

Depreciation and Amortization increased $3 million due primarily to our solar projects which commenced operations in 2010.

Income from Equity Method Investments decreased $13 million due primarily to lower earnings and an impairment recorded at GWF Power in 2010.

Other Income and (Deductions) The net increase of $39 million was due primarily to the absence of the premium paid on the debt exchange with Power in 2009 combined with gains of $3 million on the investments in our Rabbi Trust.

Interest Expense decreased $26 million due primarily to lower debt balances following the debt exchange with Power.

Income Tax Expense decreased $8 million due primarily to lower gains on sales of leveraged lease assets, partially offset by an increase to the reserve for unrecognized taxes and the absence of the tax benefit related to the premium paid on the debt exchange with Power in 2009.

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.

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

Income from Equity Method Investments increased $8 million due primarily to the absence of the impairment on PPN recorded in 2008 which was partially offset by the impairment of GWF in 2009.

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Other Income and (Deductions) The net decrease of $52 million was 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 leveraged leases and other assets in 2009, partially offset by a $57 million decrease to 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 and Dispositions 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. 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 billion multi-year syndicated credit facility. This facility is available to back-stop PSEG s $1 billion commercial paper program, issue letters of credit and for general corporate purposes. This facility may also be used to provide support to Power for the issuance of letters of credit. PSEG s credit facility 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 PSEG 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 senior unsecured debt to raise long-term capital.

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.

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For the year ended December 31, 2010, our operating cash flow increased by $309 million. For the year ended December 31, 2009, our operating cash flow decreased by $490 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power s operating cash flow decreased $92 million from $1,658 million to $1,566 million for the year ended December 31, 2010, as compared to 2009, primarily resulting from lower earnings for the year combined with

- a $214 million decrease from net collection of counterparty receivables, and
- an increase of $60 million in net cash collateral payments,
- partially offset by an increase of $132 million from lower net payments of counterparty payables.

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.

PSE&G

PSE&G s operating cash flow increased $54 million from $957 million to $1,011 million for the year ended December 31, 2010 as compared to 2009, due primarily to higher earnings combined with

- a $142 million increase in depreciation and amortization due to higher collections of securitized costs and amounts related to plant additions, a $102 million net increase in other working capital including increased customer advances, increased collections for third party suppliers and lower injuries and damages, and

partially offset by $173 million in lower collections of customer receivables, and

$47 million in lower net collection of deferred expenses, primarily the SBC and MTC refund.

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.

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Energy Holdings

Energy Holdings operating cash flow improved by $389 million for the year ended December 31, 2010, as compared to 2009. The increase was mainly attributable to lower tax payments in 2010 due to reduced lease sale activity this year and the $140 million additional tax deposit made with the IRS in June 2009.

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.

Short-Term Liquidity

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, 2010 were as follows:

	As of December 31, 2010		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
		Millions	
PSEG	$ 1,000	$ 77	$ 923
Power	2,050	223	1,827
PSE&G	600	0	600
Total	**$ 3,650**	**$ 300**	**$ 3,350**

As of December 31, 2010, our total credit facility capacity was in excess of our anticipated maximum liquidity requirements through 2011. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities and Note 14. Schedule of Consolidated Debt.

Long-Term Debt Financing

Power has approximately $606 million of a debt maturity upcoming in April 2011, as well as $44 million of tax exempt bonds that has a letter of credit expiring in 2011. PSE&G has $264 million of tax exempt bonds subject to a mandatory put in 2011, excluding securitized debt. We have not yet determined whether we will refinance or remarket these obligations during 2011.

For a discussion of our long-term debt transactions during 2010 and into 2011, see Item 8. Financial Statements and Supplementary Data Note 14. 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.

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As of December 31, 2010, PSE&G s Mortgage coverage ratio was 3.6 to 1 and the Mortgage would permit up to approximately $2.0 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 13. 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

	For the Years Ended December 31,		
Dividend Payments on Common Stock	**2010**	**2009**	**2008**
Per Share	$ 1.37	$ 1.33	$ 1.29
in Millions	$ 693	$ 673	$ 655

On February 15, 2011, our Board of Directors approved a $0.3425 per share common stock dividend for the first quarter of 2011. 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 businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors may deem relevant.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances 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 November 2010, Fitch issued updated credit opinions on PSEG, Power and PSE&G, which kept the ratings and outlook unchanged. In September and October 2010, Moody s published updated credit opinions for PSEG, Power and PSE&G, which kept the ratings and outlooks unchanged. In September, October and December 2010, S&P published updated credit opinions for PSEG, Power and PSE&G, 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.

Other Comprehensive Income

For the year ended December 31, 2010, we had Other Comprehensive Loss of $40 million on a consolidated basis. Other Comprehensive Loss was due primarily to $69 million of unrealized losses on derivative contracts accounted for as hedges, partially offset by $23 million decrease in our consolidated liability for pension and postretirement benefits and $6 million of net unrealized gains related to Available-for-Sale securities.

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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.

	2011	2012	2013
Power:		Millions	
Baseline Maintenance	$ 190	$ 235	$ 155
Environmental / Regulatory	95	65	85
Fossil Growth Opportunities	265	65	0
Nuclear Expansion	120	120	100
Total Power	**$ 670**	**$ 485**	**$ 340**
PSE&G:			
Transmission			
Reliability Enhancements	$ 540	$ 725	$ 980
Facility Replacement	125	185	155
Support Facilities	5	10	10
Distribution			
Support Facilities	35	35	40
New Business	125	130	140
Reliability Enhancements	80	60	70
Facility Replacement	205	135	140
Environmental/Regulatory	35	30	35
Renewables / EMP	320	195	30
Total PSE&G	**$ 1,470**	**$ 1,505**	**$ 1,600**
Non-Utility Renewables	140	175	215
Other	45	40	25
Total PSEG	**$ 2,325**	**$ 2,205**	**$ 2,180**

Power

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

Baseline Maintenance investments to replace major parts and maintain operational performance.

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

Fossil Growth Opportunities investments associated with potential opportunities to build other new plants, such as peaking facilities.

- Nuclear Expansion investments associated with various capital projects at existing facilities to either extend plants useful lives or increase operating output as well as costs associated with acquiring an Early Site Permit for a potential new nuclear plant at our existing location.

In 2010, Power made $645 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $180 million for nuclear fuel, primarily related to the construction of pollution control equipment at its Hudson and Mercer facilities and various projects at Nuclear.

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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 environmental, regulatory or legal mandates.

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

In 2010, PSE&G made $1,284 million of capital expenditures, including $1,257 million of investment in plant, primarily for transmission and distribution system reliability and $27 million in solar loan investments. This does not include $58 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 Item 8. Financial Statements and Supplementary Data -Note 13. 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 14. Schedule of

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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 20. Income Taxes for additional information.

	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	$ 64	$ 64	$ 0	$ 0	$ 0
Long-Term Recourse Debt Maturities					
Power	3,473	650	966	550	1,307
PSE&G	4,291	264	1,025	550	2,452
Transition Funding (PSE&G)	1,090	195	419	476	0
Transition Funding II (PSE&G)	55	11	24	20	0
Long-Term Non-Recourse Project Financing					
Energy Holdings	47	1	3	18	25
Interest on Recourse Debt					
Power	1,531	191	263	211	866
PSE&G	2,901	217	409	299	1,976
Transition Funding (PSE&G)	205	69	98	38	0
Transition Funding II (PSE&G)	7	3	3	1	0
Interest on Non-Recourse Project Financing					
Energy Holdings	16	2	4	5	5
Capital Lease Obligations					
PSEG	35	8	14	13	0
Power	8	1	4	3	0
Operating Lease Obligations					
PSE&G	11	4	4	2	1
Energy Holdings	4	1	2	1	0
Energy-Related Purchase Commitments					
Power	3,117	1,049	1,162	738	168
Total Contractual Cash Obligations	**$ 16,855**	**$ 2,730**	**$ 4,400**	**$ 2,925**	**$ 6,800**
Commercial Commitments					
Standby Letters of Credit					
Power	$ 236	$ 236	$ 0	$ 0	$ 0
Guarantees and Equity Commitments					
Energy Holdings	2	2	0	0	0
Total Commercial Commitments	**$ 238**	**$ 238**	**$ 0**	**$ 0**	**$ 0**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 32	$ 32	$ 0	$ 0	$ 0
Power	48	48	0	0	0
PSE&G	56	56	0	0	0
Energy Holdings	439	439	0	0	0

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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 13. 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 on 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 $73 million of long-term debt on their combined Consolidated Balance Sheets. Our pro-rata share of such debt is $37 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.

Through Energy Holdings, we have 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 collectability 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	2010	2009	2008
Discount Rate	5.51%	5.91%	6.80%
Rate of Return on Plan Assets	8.50%	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 $126 million, net of amounts capitalized, and contributions of up to $415 million in 2011.

***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 5.51% discount rate for 2012 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.

		As of 12/31/2010	
		Impact on Pension Benefit Obligation	**Increase to Pension Expense in 2011**
Assumption	**Change**	Millions	
Discount Rate	-1%	$ 550	$ 52
Rate of Return on Plan Assets	-1%	$ 0	$ 38

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

Accounting for Deferred Taxes

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
- the continued availability of certain tax planning strategies.

As of December 31, 2010, we do not believe a valuation allowance was necessary.

***Effect if Different Assumptions Used*:** Our ability to realize the deferred tax assets is 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 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, 2010 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 from contracts listed on exchanges or 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 Income (Loss), net of tax, or as a Regulatory Asset (Liability). Amounts in Accumulated Other Comprehensive Income (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 Income (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.

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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 of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data Note 16. Financial Risk Management Activities.

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 Income (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 Consolidated 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 Income (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 17. 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 (ARO)

Power, PSE&G and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs 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. The most recent cost study was done in 2009. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset.

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Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power s nuclear facilities comprised 91% of Power s total AROs as of December 31, 2010. 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; and
- 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 $100 million increase in the Nuclear ARO as of December 31, 2010. A 1% increase in the inflation rate used at December 31, 2009 would result in a $176 million increase in the Nuclear ARO as of December 31, 2010. 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 $70 million at December 31, 2010. These changes would not have a material impact on net income in 2011.

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 BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

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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, as appropriate.

***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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss 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 executive officers who utilize a risk oversight function to 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 physical sales and other services, 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 owned 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. While we manage our risk at the portfolio level, we also monitor separately the risk of our trading activities and hedges. Non-trading 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 MTM trading and non-trading 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.

As of December 31, 2010 and 2009, Trading VaR was approximately $1 million.

For the Year Ended December 31, 2010	Trading VaR	Non-Trading MTM VaR
	Millions	
95% Confidence level,		
Loss could exceed VaR one day in 20 days		
Period End	$ 1	$ 9
Average for the Period	$ 1	$ 11
High	$ 2	$ 29
Low	$ 0	$ 4
99.5% Confidence level,		
Loss could exceed VaR one day in 200 days		
Period End	$ 1	$ 14
Average for the Period	$ 1	$ 17
High	$ 3	$ 45
Low	$ 0	$ 6

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2010, 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 $227 million decrease in the fair value of debt, including a $76 million decrease at Power and a $145 million decrease at PSE&G.

Debt and Equity Securities

We have $3.6 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 $1.4 billion as of December 31, 2010. The fair value of equity securities is determined independently each month by the trustee. As of December 31, 2010, the portfolio was comprised of $735 million of equity securities and $628 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, 2010, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Funds by approximately $74 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 component of the NDT Funds currently has a duration of 4.98 years and a yield of 2.97%. The portfolio s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2010, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $28 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data Note 16. 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 leases, totaling $356 million, which is net of deferred taxes of $899 million, as of December 31, 2010. These investments are primarily leveraged leases concentrated in the United States energy industry. See Item 8. Financial Statements and Supplementary Data -Note. 8. Financing Receivables for counterparties credit ratings and other information. 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, 2010 and 2009, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, 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.

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, 2010, 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 25, 2011 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey

February 25, 2011

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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, 2010 and 2009, 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, 2010. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, 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.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey

February 25, 2011

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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, 2010 and 2009, 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, 2010. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, 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.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey

February 25, 2011

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31, 2010	2009	2008
OPERATING REVENUES	$ 11,793	$ 12,035	$ 12,609
OPERATING EXPENSES			
Energy Costs	5,261	5,433	6,800
Operation and Maintenance	2,504	2,534	2,414
Depreciation and Amortization	955	819	775
Taxes Other Than Income Taxes	136	133	136
Total Operating Expenses	8,856	8,919	10,125
OPERATING INCOME	2,937	3,116	2,484
Income from Equity Method Investments	4	17	10
Other Income	221	246	434
Other Deductions	(63)	(161)	(336)
Other-Than-Temporary Impairments	(11)	(61)	(220)
Interest Expense	(472)	(521)	(566)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,616	2,636	1,806
Income Tax (Expense) Benefit	(1,059)	(1,042)	(888)
INCOME FROM CONTINUING OPERATIONS	1,557	1,594	918
Income (Loss) from Discontinued Operations, net of tax expense of $8, $2 and $209 for the years ended 2010, 2009 and 2008, respectively	7	(2)	270
NET INCOME	$ 1,564	$ 1,592	$ 1,188
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,985	505,986	507,693
DILUTED	507,045	507,064	508,427
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$ 3.08	$ 3.15	$ 1.81
NET INCOME	$ 3.09	$ 3.15	$ 2.34
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$ 3.07	$ 3.14	$ 1.81
NET INCOME	$ 3.08	$ 3.14	$ 2.34
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 1.37	$ 1.33	$ 1.29

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 280	$ 350
Accounts Receivable, net of allowances of $68 and $79 in 2010 and 2009, respectively	1,387	1,224
Tax Receivable	689	0
Unbilled Revenues	400	411
Fuel	666	806
Materials and Supplies, net	359	335
Prepayments	204	161
Derivative Contracts	182	225
Assets of Discontinued Operations	564	603
Deferred Income Taxes	43	0
Regulatory Assets	155	142
Other	122	33
Total Current Assets	5,051	4,290
PROPERTY, PLANT AND EQUIPMENT	23,272	21,416
Less: Accumulated Depreciation and Amortization	(6,882)	(6,530)
Net Property, Plant and Equipment	16,390	14,886
NONCURRENT ASSETS		
Regulatory Assets	3,736	4,260
Regulatory Assets of Variable Interest Entities (VIEs)	1,128	1,367
Long-Term Investments	1,623	2,032
Nuclear Decommissioning Trust (NDT) Funds	1,363	1,199
Other Special Funds	160	149
Goodwill	16	16
Other Intangibles	136	123
Derivative Contracts	79	123
Restricted Cash of VIEs	21	17
Other	206	216
Total Noncurrent Assets	8,468	9,502
TOTAL ASSETS	$ 29,909	$ 28,678

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2010	December 31, 2009
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 915	$ 323
Securitization Debt of VIEs Due Within One Year	206	198
Commercial Paper and Loans	64	530
Accounts Payable	1,176	1,075
Derivative Contracts	103	201
Accrued Interest	108	102
Accrued Taxes	49	89
Clean Energy Program	195	166
Obligation to Return Cash Collateral	104	95
Deferred Income Taxes	0	7
Regulatory Liabilities	174	156
Liabilities of Discontinued Operations	72	69
Other	319	349
Total Current Liabilities	3,485	3,360
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,129	4,045
Regulatory Liabilities	285	293
Regulatory Liabilities of VIEs	8	7
Asset Retirement Obligations	461	439
Other Postretirement Benefit (OPEB) Costs	967	1,095
Accrued Pension Costs	788	1,094
Clean Energy Program	235	400
Environmental Costs	669	704
Derivative Contracts	22	40
Long-Term Accrued Taxes	248	538
Other	152	140
Total Noncurrent Liabilities	8,964	8,795
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,834	6,481
Securitization Debt of VIEs	939	1,145
Project Level, Non-Recourse Debt	46	19
Total Long-Term Debt	7,819	7,645
SUBSIDIARY S PREFERRED STOCK WITHOUT MANDATORY REDEMPTION	0	80
STOCKHOLDERS EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2010 and 2009 533,556,660 shares	4,807	4,788

Treasury Stock, at cost, 2010 27,582,437 shares; 2009 27,567,030 shares	(593)	(588)
Retained Earnings	5,575	4,704
Accumulated Other Comprehensive Loss	(156)	(116)
Total Common Stockholders Equity	9,633	8,788
Noncontrolling Interest	8	10
Total Stockholders Equity	9,641	8,798
Total Capitalization	17,460	16,523
TOTAL LIABILITIES AND CAPITALIZATION	$ 29,909	$ 28,678

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,		
	2010	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,564	$ 1,592	$ 1,188
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	0	0	(335)
Depreciation and Amortization	974	838	793
Amortization of Nuclear Fuel	136	121	101
Provision for Deferred Income Taxes (Other than Leases) and ITC	1,106	326	71
Non-Cash Employee Benefit Plan Costs	315	347	167
Lease Transaction Reserves, net of tax	0	(29)	490
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(336)	(678)	51
Net (Gain) Loss on Lease Investments	(56)	(167)	(11)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	50	25	(39)
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	(36)	(32)	(43)
Over (Under) Recovery of Societal Benefits Charge (SBC)	(123)	4	(75)
Market Transition Charge Refund, net	84	0	0
Cost of Removal	(58)	(54)	(44)
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(106)	(50)	115
Net Change in Tax Receivable	(689)	0	0
Net Change in Certain Current Assets and Liabilities	(221)	221	74
Employee Benefit Plan Funding and Related Payments	(508)	(446)	(139)
Other	68	(163)	(19)
Net Cash Provided By (Used In) Operating Activities	2,164	1,855	2,345
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,160)	(1,794)	(1,771)
Proceeds from Sale of Discontinued Operations	0	0	925
Proceeds from the Sale of Capital Leases and Investments	496	880	77
Proceeds from Sales of Available-for-Sale Securities	1,116	1,769	3,060
Investments in Available-for-Sale Securities	(1,140)	(1,798)	(3,093)
Restricted Funds	(2)	116	(11)
Other	21	35	38
Net Cash Provided By (Used In) Investing Activities	(1,669)	(792)	(775)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	(466)	511	(46)
Issuance of Long-Term Debt	1,728	459	1,075
Purchase of Common Treasury Stock	0	0	(92)
Redemption of Long-Term Debt	(775)	(820)	(1,582)
Repayment of Non-Recourse Debt	(32)	(286)	(56)
Redemption of Securitization Debt	(197)	(187)	(179)
Premium Paid on Debt Exchange/Redemption	(18)	(36)	(79)
Cash Dividends Paid on Common Stock	(693)	(673)	(655)
Redemption of Preferred Securities	(80)	0	0

Other	(32)	(2)	(15)
Net Cash Provided By (Used In) Financing Activities	(565)	(1,034)	(1,629)
Net Increase (Decrease) in Cash and Cash Equivalents	(70)	29	(59)
Cash and Cash Equivalents at Beginning of Period	350	321	380
Cash and Cash Equivalents at End of Period	$ 280	$ 350	$ 321
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 1,070	$ 1,364	$ 952
Interest Paid, Net of Amounts Capitalized	$ 444	$ 500	$ 557

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			Accumulated Other		
					Retained	Comprehensive	Noncontrolling	
	Shs.	Amount	Shs.	Amount	Earnings	Loss	Interest	Total
Balance as of January 1, 2008	534	$ 4,732	(25)	$ (478)	$ 3,261	$ (216)	$ 6	$ 7,305
Net Income	0	0	0	0	1,188	0	0	1,188
Other Comprehensive Income (Loss), net of tax:								
Currency Translation Adjustment, net of tax	0	0	0	0	0	(106)	0	(106)
Available-for-Sale Securities, net of tax	0	0	0	0	0	(79)	0	(79)
Change in Fair Value of Derivative Instruments, net of tax	0	0	0	0	0	253	0	253
Reclassification Adjustments for Net Amounts included in Net Income, net of tax	0	0	0	0	0	176	0	176
Pension/OPEB adjustment, net of tax	0	0	0	0	0	(205)	0	(205)
Other Comprehensive Income								39
Comprehensive Income								1,227
Adoption of Accounting Guidance for Fair Value Measurements, net of tax	0	0	0	0	(21)	0	0	(21)
Cash Dividends on Common Stock	0	0	0	0	(655)	0	0	(655)
Repurchase of Common Stock	0	0	(3)	(92)	0	0	0	(92)
Investment by Noncontrolling Interest	0	0	0	0	0	0	5	5
Other	0	24	0	(11)	0	0	0	13
Balance as of December 31, 2008	534	$ 4,756	(28)	$ (581)	$ 3,773	$ (177)	$ 11	$ 7,782
Net Income	0	0	0	0	1,592	0	0	1,592
Other Comprehensive Income (Loss), net of tax:								
Available-for-Sale Securities, net of tax	0	0	0	0	0	94	0	94
Change in Fair Value of Derivative Instruments, net of tax	0	0	0	0	0	356	0	356
Reclassification Adjustments for Net Amounts included in Net Income, net of tax	0	0	0	0	0	(348)	0	(348)
Pension/OPEB adjustment, net of tax	0	0	0	0	0	(29)	0	(29)
Other Comprehensive Income								73
Comprehensive Income								1,665
Adoption of Accounting Guidance for Non-Credit Losses, net of tax	0	0	0	0	12	(12)	0	0
Cash Dividends on Common Stock	0	0	0	0	(673)	0	0	(673)
Noncontrolling Interest in Losses of Consolidated Entity	0	0	0	0	0	0	(1)	(1)
Other	0	32	0	(7)	0	0	0	25
Balance as of December 31, 2009	534	$ 4,788	(28)	$ (588)	$ 4,704	$ (116)	$ 10	$ 8,798

Net Income	0	0	0	0	1,564	0	0	1,564
Other Comprehensive Income (Loss), net of tax:								
Available-for-Sale Securities, net of tax	0	0	0	0	0	6	0	6
Change in Fair Value of Derivative Instruments, net of tax	0	0	0	0	0	60	0	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax	0	0	0	0	0	(129)	0	(129)
Pension/OPEB adjustment, net of tax	0	0	0	0	0	23	0	23
Other Comprehensive Income (Loss)								(40)
Comprehensive Income								1,524
Cash Dividends on Common Stock	0	0	0	0	(693)	0	0	(693)
Noncontrolling Interest in Losses of Consolidated Entity	0	0	0	0	0	0	(2)	(2)
Other	0	19	0	(5)	0	0	0	14
Balance as of December 31, 2010	534	$ 4,807	(28)	$ (593)	$ 5,575	$ (156)	$ 8	$ 9,641

See Notes to Consolidated Financial Statements.

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PSEG POWER LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31,		
	2010	2009	2008
OPERATING REVENUES	$ 6,558	$ 6,772	$ 7,770
OPERATING EXPENSES			
Energy Costs	3,374	3,462	4,556
Operation and Maintenance	1,046	1,045	1,054
Depreciation and Amortization	175	184	164
Total Operating Expenses	4,595	4,691	5,774
OPERATING INCOME	1,963	2,081	1,996
Other Income	170	233	414
Other Deductions	(53)	(135)	(316)
Other-Than-Temporary Impairments	(9)	(60)	(219)
Interest Expense	(157)	(161)	(164)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,914	1,958	1,711
Income Tax (Expense) Benefit	(778)	(767)	(661)
INCOME FROM CONTINUING OPERATIONS	1,136	1,191	1,050
Income (Loss) from Discontinued Operations, net of tax expense of $8, $2 and $38 for the years ended 2010, 2009 and 2008, respectively	7	(2)	65
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 1,143	$ 1,189	$ 1,115

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, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 11	$ 64
Accounts Receivable	511	420
Accounts Receivable Affiliated Companies, net	782	459
Short-Term Loan to Affiliate	398	0
Fuel	666	806
Materials and Supplies, net	269	264
Derivative Contracts	163	213
Prepayments	80	64
Assets of Discontinued Operations	564	603
Other	0	3
Total Current Assets	3,444	2,896
PROPERTY, PLANT AND EQUIPMENT	8,643	7,926
Less: Accumulated Depreciation and Amortization	(2,301)	(2,095)
Net Property, Plant and Equipment	6,342	5,831
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Funds	1,363	1,199
Goodwill	16	16
Other Intangibles	130	114
Other Special Funds	32	30
Derivative Contracts	42	118
Long-Term Accrued Taxes	16	39
Other	67	90
Total Noncurrent Assets	1,666	1,606
TOTAL ASSETS	$ 11,452	$ 10,333

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, 2010	December 31, 2009
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 650	$ 0
Accounts Payable	643	616
Short-Term Loan from Affiliate	0	194
Derivative Contracts	91	201
Deferred Taxes	64	0
Accrued Interest	40	43
Liabilities of Discontinued Operations	72	69
Other	91	135
Total Current Liabilities	1,651	1,258
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,146	609
Asset Retirement Obligations	242	226
Other Postretirement Benefit (OPEB) Costs	151	158
Derivative Contracts	22	26
Accrued Pension Costs	253	344
Environmental Costs	51	52
Other	104	72
Total Noncurrent Liabilities	1,969	1,487
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT		
Total Long-Term Debt	2,805	3,121
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,080	3,486
Accumulated Other Comprehensive Loss	(95)	(61)
Total Member's Equity	5,027	4,467
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,452	$ 10,333

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, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,143	$ 1,189	$ 1,115
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	194	203	181
Amortization of Nuclear Fuel	136	121	101
Interest Accretion on Asset Retirement Obligations	18	27	25
Provision for Deferred Income Taxes and ITC	650	133	64
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	50	25	(39)
Non-Cash Employee Benefit Plan Costs	71	76	23
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(106)	(50)	115
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	135	97	(163)
Margin Deposit	(91)	(31)	319
Accounts Receivable	(105)	109	6
Accounts Payable	17	(115)	29
Accounts Receivable/Payable-Affiliated Companies, net	(386)	75	(17)
Other Current Assets and Liabilities	(66)	(27)	60
Employee Benefit Plan Funding and Related Payments	(132)	(114)	(20)
Other	38	(60)	7
Net Cash Provided By (Used In) Operating Activities	1,566	1,658	1,806
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(825)	(869)	(978)
Settlement of Spent Nuclear Fuel Claim	16	47	0
Proceeds from Sales of Available-for-Sale Securities	989	1,769	3,060
Investments in Available-for-Sale Securities	(1,013)	(1,798)	(3,093)
Short-Term Loan Affiliated Company, net	(398)	55	(55)
Restricted Funds	2	115	(10)
Other	24	29	35
Net Cash Provided By (Used In) Investing Activities	(1,205)	(652)	(1,041)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	594	209	0
Contributed Capital	0	230	0
Cash Dividend Paid	(549)	(940)	(500)
Redemption of Long-Term Debt	(248)	(294)	0
Redemption of Non-Recourse Long-Term Debt	0	(280)	(50)
Short-Term Loan Affiliated Company, net	(194)	194	(194)
Cash Payment for Debt Exchange	(13)	(101)	0
Other	(4)	0	0
Net Cash Provided By (Used In) Financing Activities	(414)	(982)	(744)

Net Increase (Decrease) in Cash and Cash Equivalents		(53)		24		21
Cash and Cash Equivalents at Beginning of Period		64		40		19
Cash and Cash Equivalents at End of Period	$	11	$	64	$	40
Supplemental Disclosure of Cash Flow Information:						
Income Taxes Paid (Received)	$	539		584	$	552
Interest Paid, Net of Amounts Capitalized	$	151	$	160	$	184

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, 2008	$ 2,202	$ (986)	$ 2,631	$ (296)	$ 3,551
Net Income	0	0	1,115	0	1,115
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax	0	0	0	(79)	(79)
Change in Fair Value of Derivative Instruments, net of tax	0	0	0	257	257
Reclassification Adjustments for Net Amount included in Net Income, net of tax	0	0	0	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	0	0	(21)	0	(21)
Cash Dividends Paid	0	0	(500)	0	(500)
Balance as of December 31, 2008	$ 2,202	$ (986)	$ 3,225	$ (119)	$ 4,322
Net Income	0	0	1,189	0	1,189
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax	0	0	0	88	88
Change in Fair Value of Derivative Instruments, net of tax	0	0	0	358	349
Reclassification Adjustments for Net Amount included in Net Income, net of tax	0	0	0	(350)	(341)
Pension/OPEB adjustment, net of tax	0	0	0	(26)	(26)
Other Comprehensive Income					70
Comprehensive Income					1,259
Non-Cash Return of Capital Related to Debt Exchange	(404)	0	0	0	(404)
Adoption of Accounting Guidance for Non-Credit Losses, net of tax	0	0	12	(12)	0
Contributed Capital	230	0	0	0	230
Cash Dividends Paid	0	0	(940)	0	(940)
Balance as of December 31, 2009	$ 2,028	$ (986)	$ 3,486	$ (61)	$ 4,467
Net Income	0	0	1,143	0	1,143
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax	0	0	0	15	15

Change in Fair Value of Derivative Instruments, net of tax	0	0	0	60	60
Reclassification Adjustments for Net Amount included in Net Income, net of tax	0	0	0	(129)	(129)
Pension/OPEB adjustment, net of tax	0	0	0	21	21
Other	0	0	0	(1)	(1)
Other Comprehensive Income					(34)
Comprehensive Income					1,109
Cash Dividends Paid	0	0	(549)	0	(549)
Balance as of December 31, 2010	$ 2,028	$ (986)	$ 4,080	$ (95)	$ 5,027

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,		
	2010	**2009**	**2008**
OPERATING REVENUES	$ 7,869	$ 8,243	$ 9,038
OPERATING EXPENSES			
Energy Costs	4,655	5,170	6,072
Operation and Maintenance	1,442	1,474	1,338
Depreciation and Amortization	750	608	583
Taxes Other Than Income Taxes	136	133	136
Total Operating Expenses	6,983	7,385	8,129
OPERATING INCOME	886	858	909
Other Income	26	8	12
Other Deductions	(3)	(3)	(4)
Interest Expense	(318)	(312)	(325)
INCOME BEFORE INCOME TAXES	591	551	592
Income Tax (Expense) Benefit	(232)	(226)	(228)
NET INCOME	359	325	364
Preferred Stock Dividends	(1)	(4)	(4)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 358	$ 321	$ 360

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, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 245	$ 240
Accounts Receivable, net of allowances of $67 in 2010 and $78 in 2009, respectively	832	800
Unbilled Revenues	400	411
Materials and Supplies	90	70
Prepayments	117	86
Regulatory Assets	155	142
Other	19	3
Total Current Assets	1,858	1,752
PROPERTY, PLANT AND EQUIPMENT	14,068	12,933
Less: Accumulated Depreciation and Amortization	(4,326)	(4,187)
Net Property, Plant and Equipment	9,742	8,746
NONCURRENT ASSETS		
Regulatory Assets	3,736	4,260
Regulatory Assets of VIEs	1,128	1,367
Long-Term Investments	230	204
Other Special Funds	54	51
Derivative Contracts	17	5
Restricted Cash of VIEs	21	17
Other	87	79
Total Noncurrent Assets	5,273	5,983
TOTAL ASSETS	$ 16,873	$ 16,481

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, 2010	December 31, 2009
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 264	$ 300
Securitization Debt of VIEs Due Within One Year	206	198
Accounts Payable	406	337
Accounts Payable Affiliated Companies, net	85	496
Accrued Interest	65	56
Clean Energy Program	195	166
Derivative Contracts	12	0
Deferred Taxes	19	7
Obligation to Return Cash Collateral	104	95
Regulatory Liabilities	174	156
Other	229	162
Total Current Liabilities	1,759	1,973
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,127	2,651
Other Postretirement Benefit (OPEB) Costs	770	887
Accrued Pension Costs	377	565
Regulatory Liabilities	285	293
Regulatory Liabilities of VIEs	8	7
Clean Energy Program	235	400
Environmental Costs	617	652
Asset Retirement Obligations	216	211
Long-Term Accrued Taxes	74	96
Other	23	29
Total Noncurrent Liabilities	5,732	5,791
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,019	3,271
Securitization Debt of VIEs	939	1,145
Total Long-Term Debt	4,958	4,416
Preferred Stock Without Mandatory Redemption, $100 par value, 7,500,000 authorized; issued and outstanding, 2009 795,234 shares	0	80
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2010 and 2009 132,450,344 shares	892	892
Contributed Capital	420	420
Basis Adjustment	986	986
Retained Earnings	2,126	1,918

Accumulated Other Comprehensive Income	0	5
Total Stockholder's Equity	4,424	4,221
Total Capitalization	9,382	8,717
TOTAL LIABILITIES AND CAPITALIZATION	$ 16,873	$ 16,481

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,		
	2010	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 359	$ 325	$ 364
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	750	608	583
Provision for Deferred Income Taxes and ITC	444	194	86
Non-Cash Employee Benefit Plan Costs	217	236	129
Cost of Removal	(58)	(54)	(44)
Market Transition Charge (MTC) Refund, net	84	0	0
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	(36)	(32)	(43)
Over (Under) Recovery of SBC	(123)	4	(75)
Net Changes in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(21)	152	(19)
Materials and Supplies	(20)	(9)	(8)
Prepayments	(31)	(41)	12
Accounts Receivable/Payable Affiliated Companies, net	(286)	(62)	(8)
Other Current Assets and Liabilities	68	(34)	19
Employee Benefit Plan Funding and Related Payments	(327)	(288)	(108)
Other	(9)	(42)	25
Net Cash Provided By (Used In) Operating Activities	1,011	957	913
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,257)	(855)	(761)
Proceeds from Sales of Available-for-Sale Securities	54	1	0
Investments in Available-for-Sale Securities	(54)	(1)	0
Solar Loan Investments	(27)	(43)	0
Other	4	5	0
Net Cash Provided By (Used In) Investing Activities	(1,280)	(893)	(761)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	0	(19)	(46)
Issuance of Long-Term Debt	1,114	250	1,075
Redemption of Long-Term Debt	(400)	(203)	(901)
Redemption of Securitization Debt	(197)	(187)	(179)
Redemption of Preferred Securities	(80)	0	0
Contributed Capital	0	250	0
Deferred Issuance Costs	(10)	(2)	(6)
Premium Paid on Early Retirement of Debt	0	0	(32)
Common Stock Dividend	(150)	0	0
Preferred Stock Dividends	(1)	(4)	(4)
Other	(2)	0	0
Net Cash Provided By (Used In) Financing Activities	274	85	(93)

Net Increase (Decrease) In Cash and Cash Equivalents	5	149	59
Cash and Cash Equivalents at Beginning of Period	240	91	32
Cash and Cash Equivalents at End of Period	$ 245	$ 240	$ 91
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 73	$ 5	$ 125
Interest Paid, Net of Amounts Capitalized	$ 294	$ 299	$ 317

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 Income	Total
Balance as of January 1, 2008	$ 892	$ 170	$ 986	$ 1,237	$ 2	$ 3,287
Net Income	0	0	0	364	0	364
Comprehensive Income						364
Cash Dividends on Preferred Stock	0	0	0	(4)	0	(4)
Balance as of December 31, 2008	$ 892	$ 170	$ 986	$ 1,597	$ 2	$ 3,647
Net Income	0	0	0	325	0	325
Other Comprehensive Income, net of tax:	0	0	0	0	3	3
Comprehensive Income						328
Contributed Capital	0	250	0	0	0	250
Cash Dividends on Preferred Stock	0	0	0	(4)	0	(4)
Balance as of December 31, 2009	$ 892	$ 420	$ 986	$ 1,918	$ 5	$ 4,221
Net Income	0	0	0	359	0	359
Other Comprehensive Loss, net of tax:	0	0	0	0	(5)	(5)
Comprehensive Income						354
Cash Dividends on Preferred Stock	0	0	0	(1)	0	(1)
Cash Dividends on Common Stock	0	0	0	(150)	0	(150)
Balance as of December 31, 2010	$ 892	$ 420	$ 986	$ 2,126	$ 0	$ 4,424

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 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).

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 3. 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 23. Related-Party Transactions.

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. Power s and PSE&G s revenues and expenses related to these facilities are consolidated 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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) or as a Regulatory Asset (Liability) as applicable 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, 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 16. 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 16. 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 primarily 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 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

nuclear generation assets 60 years to 61 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 as follows:

	2010 Avg Rate	2009 Avg Rate	2008 Avg Rate
PSE&G Depreciation Rate	2.46%	2.44%	2.47%

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, 2010, 2009 and 2008, combined TEFA and GRT are included in the following captions in the Consolidated Statements of Operations:

	Years Ended December 31,		
	2010	2009	2008
		Millions	
TEFA and GRT included in:			
Operating Revenues	$ 149	$ 146	$ 150
Taxes Other Than Income Taxes	$ 136	$ 133	$ 136

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, 2010, 2009 and 2008 are as follows:

	IDC/AFUDC Capitalized					
	2010		2009		2008	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
Power	$ 78	6.57%	$ 58	6.78%	$ 44	6.63%
PSE&G	$ 7	6.22%	$ 1	0.88%	$ 4	3.46%

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 20. Income Taxes for further discussion.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash and Cash Equivalents

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

Accounts Receivable Allowance for Doubtful Accounts

PSE&G s accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G s best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

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

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.

Available-for-Sale Securities

These securities are comprised of Nuclear Decommissioning Trust (NDT) Funds, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power s nuclear facilities and amounts comprising Other Special Funds that are 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.

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 9. Available-for-Sale Securities for further discussion.

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 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 12. Pension, OPEB and Savings Plans for further discussion.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 2010. We are required to present certain consolidated amounts related to Variable Interest Entities (VIEs) separately on the face of our Consolidated Balance Sheets for PSEG and PSE&G with prior period amounts being reclassified as appropriate.

In addition, as of December 31, 2010, PSEG and PSE&G have adjusted the presentation of Regulatory Assets and Liabilities to reflect those items expected to be fully recovered or refunded within the next 12 months, and the related deferred tax amounts, as current assets and liabilities on the Consolidated Balance Sheets. Prior period amounts have been reclassified to conform with the current presentation. For additional information, see Note 6. Regulatory Assets and Liabilities.

Operating results for our two natural gas combined cycle power plants in Texas were reclassified to Income (Loss) from Discontinued Operations in the Consolidated Statements of Operations of PSEG and Power for the years ended December 31, 2010, 2009 and 2008 to reflect the pending sales of these facilities in the first half of 2011. See Note 4. Discontinued Operations and Dispositions.

Note 2. Recent Accounting Standards

New Standards Adopted during 2010

During 2010, we adopted the following 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.

Accounting for Variable Interest Entities (VIE)

This accounting standard amends the criteria used to determine which enterprise has a controlling financial interest in a VIE. The amended standard includes the following provisions:

- requires an enterprise to qualitatively assess whether it should consolidate a VIE based on whether it has (i) the power to direct the activities of a VIE that most significantly impact the economic performance of a VIE, and (ii) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE, requires an ongoing reconsideration of the primary beneficiary,

amends the VIE reconsideration events (triggering events), and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

requires additional disclosures for the enterprise that consolidates a VIE (the primary beneficiary) to present separately on the face of the consolidated balance sheet (i) assets of the consolidated VIE that can be used only to settle obligations of the consolidated VIE and (ii) liabilities of a consolidated VIE for which creditors have no recourse to the general credit of the primary beneficiary.

We adopted the standard on January 1, 2010 and there was no impact on our financial statements upon initial adoption, other than presentation and disclosure. In accordance with the guidance, we continuously assess the primary beneficiaries of VIEs for which we have a variable interest. See Note 3. Variable Interest Entities for further information.

Disclosures about Credit Quality of Financing Receivables and Allowance for Credit Losses

This accounting standard update was issued to provide greater transparency about an entity s allowance for credit losses and the credit quality of its financing receivables by requiring:

- quantitative and qualitative information about the credit quality of financing receivables,
- a description of accounting policies and methodology used to estimate the allowance for credit losses, and
- an analysis of financing receivables on nonaccrual or past due status.

We adopted the standard effective December 31, 2010 and have enhanced disclosures as required by the standard. See Note 8. Financing Receivables for further information.

New Accounting Standards Issued But Not Yet Adopted

Revenue Arrangements with Multiple Deliverables

- amends existing guidance for identifying separate deliverables in a revenue-generating transaction where multiple deliverables exist,
- establishes a selling price hierarchy, such as, vendor-specific objective evidence, third-party evidence and estimated selling price for determining the selling price of a deliverable, and
- provides guidance for allocating and recognizing revenue based on separate deliverables.

We adopted this standard, prospectively effective January 1, 2011, for new and significantly modified revenue arrangements. We do not anticipate a material impact on our financial statements as a result of this new guidance.

Note 3. Variable Interest Entities

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary of and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created 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.

The assets and liabilities of these VIEs are presented separately on the face of the Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. The Transition Funding and Transition Funding II creditors do not have any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding and Transition Funding II, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G s maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of December 31, 2010 and 2009. PSE&G considers the risk of actual loss to be remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II in 2010 or 2009. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding and Transition Funding II.

Note 4. Discontinued Operations and Dispositions

Discontinued Operations

Power

In January 2011, Power reached agreements to sell two 1,000 MW combined-cycle generation facilities located in Texas that are owned and operated by its subsidiary, PSEG Texas. The plants will be sold in two separate transactions aggregating approximately $687 million and are expected to be closed in the first half of 2011.

PSEG Texas operating results for the years ended December 31, 2010, 2009 and 2008, which were reclassified to Discontinued Operations, are summarized below:

		Years Ended December 31,	
	2010	**2009**	**2008**
		Millions	
Operating Revenues	$ 402	$ 371	$ 713
Income Before Income Taxes	$ 15	$ 0	$ 103
Net Income (Loss)	$ 7	$ (2)	$ 65

The carrying amounts of PSEG Texas assets as of December 31, 2010 and 2009 are summarized in the following table:

	As of December 31,	
	2010	**2009**
	Millions	
Current Assets	$ 28	$ 49
Noncurrent Assets	536	554
Total Assets of Discontinued Operations	**$ 564**	**$ 603**
Current Liabilities	$ 28	$ 34
Noncurrent Liabilities	44	35
Total Liabilities of Discontinued Operations	**$ 72**	**$ 69**

Energy Holdings

Bioenergie

In November 2008, Energy Holdings sold its 85% ownership interest in Bioenergie for $40 million. Bioenergie owned 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Bioenergie s operating results for the year ended December 31, 2008, which were reclassified to Discontinued Operations, are summarized below:

	Year Ended December 31, 2008
	Millions
Operating Revenues	$ 40
Income Before Income Taxes	$ 5
Net Income	$ 3

SAESA Group

In July 2008, Energy Holdings sold its investment in the SAESA Group, which consisted 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 year ended December 31, 2008, which were reclassified to Discontinued Operations, are summarized below:

	Year Ended December 31, 2008
	Millions
Operating Revenues	$ 379
Income Before Income Taxes	$ 36
Net Income	$ 30

Dispositions

Energy Holdings

Leveraged Leases

For the year ended December, 31, 2010, Energy Holdings sold its interest in six leveraged leases, including five international leases for which the Internal Revenue Service (IRS) has indicated its intention to disallow certain tax deductions taken in prior years.

For the year ended December 31, 2009, Energy Holdings sold its interest in fourteen leveraged leases, including twelve international leases for which the IRS has indicated its intention to disallow certain tax deductions taken in prior years.

For the year ended December 31, 2008, Energy Holdings sold its interest in one international leveraged lease for which the IRS has indicated its intention to disallow certain tax deductions taken in prior years.

	Years Ended December 31,

	2010	2009	2008
		Millions	
Proceeds from Sales	$ 433	$ 830	$ 40
Gain (Loss) on the Sales, after-tax	$ 30	$ 70	$ 5

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Proceeds from the sales of the international leases were used to reduce the tax exposure related to these lease investments. For additional information see Note 13. Commitments and Contingent Liabilities.

GWF Energy LLC (GWF Energy)

In May 2009, Energy Holdings entered into a Memorandum of Understanding under which it would sell, in two separate transactions, its ownership interest in GWF Energy, an equity method investment, for a total purchase price of $70 million. Energy Holdings completed the first stage of the sale in June 2009 for approximately $7 million. Energy Holdings completed the second stage of the sale in September 2010 for approximately $63 million. The total proceeds from both sales approximated the book value of the investment.

Enterprise Group Development Corporation (EGDC)

In December 2010, Energy Holdings sold its EGDC assets in State Street I, II and III for a total purchase price of $46 million. The sale resulted in an after-tax gain of $4 million.

PPN Power Generating Company Limited (PPN)

In May 2009, Energy Holdings sold its ownership interest in PPN, which owned and operated a 330 MW generation facility in India for approximately book value.

Other

In May 2009, Energy Holdings sold its 6.5% interest in Midland Cogeneration Venture LP for an after-tax gain of $2 million.

Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2010 and 2009 is detailed below:

	Power	PSE&G	Other	PSEG Consolidated
2010				
Generation:				
Fossil Production	$ 6,442	$ 0	$ 0	$ 6,442
Nuclear Production	965	0	0	965
Nuclear Fuel in Service	717	0	0	717
Other Production-Solar	0	204	87	291
Construction Work in Progress	441	0	0	441
Total Generation	8,565	204	87	8,856
Transmission and Distribution:				
Electric Transmission	0	2,148	0	2,148
Electric Distribution	0	6,208	0	6,208
Gas Transmission	0	91	0	91
Gas Distribution	0	4,684	0	4,684

Construction Work in Progress	0	211	0	211
Plant Held for Future Use	0	5	0	5
Other	0	389	0	389
Total Transmission and Distribution	0	13,736	0	13,736
Other	78	128	474	680
Total	**$ 8,643**	**$ 14,068**	**$ 561**	**$ 23,272**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	PSE&G	Other	PSEG Consolidated
2009				
Generation:				
Fossil Production	$ 5,260	$ 0	$ 0	$ 5,260
Nuclear Production	833	0	0	833
Nuclear Fuel in Service	631	0	0	631
Other Production-Solar	0	13	13	26
Construction Work in Progress	1,121	0	0	1,121
Total Generation	7,845	13	13	7,871
Transmission and Distribution:				
Electric Transmission	0	1,891	0	1,891
Electric Distribution	0	5,804	0	5,804
Gas Transmission	0	95	0	95
Gas Distribution	0	4,422	0	4,422
Construction Work in Progress	0	108	0	108
Plant Held for Future Use	0	7	0	7
Other	0	421	0	421
Total Transmission and Distribution	0	12,748	0	12,748
Other	81	172	544	797
Total	**$ 7,926**	**$ 12,933**	**$ 557**	**$ 21,416**

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, 2010	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	23%	$ 254	$ 122
Keystone	23%	$ 376	$ 107
Nuclear Generating			
Peach Bottom	50%	$ 399	$ 149
Salem	57%	$ 770	$ 225
Nuclear Support Facilities	Various	$ 135	$ 21

Pumped Storage Facilities			
Yards Creek	50%	$ 32	$ 22
Merrill Creek Reservoir	14%	$ 1	$ 0
PSE&G:			
Transmission Facilities	Various	$ 148	$ 61
Linden SNG Plant	90%	$ 5	$ 5

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December 31, 2009	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	23%	$ 242	$ 117
Keystone	23%	$ 373	$ 96
Nuclear Generating			
Peach Bottom	50%	$ 300	$ 135
Salem	57%	$ 720	$ 183
Nuclear Support Facilities	Various	$ 105	$ 18
Pumped Storage Facilities			
Yards Creek	50%	$ 31	$ 22
Merrill Creek Reservoir	14%	$ 1	0
PSE&G:			
Transmission Facilities	Various	$ 146	$ 60
Linden SNG Plant	90%	$ 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. 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.

GenOn 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. Jersey Central Power and Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L 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 Storm Damage and Cape May

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Street regulatory assets, all of PSE&G s regulatory assets and liabilities at December 31, 2010 and 2009 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, 2010	2009	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current:			
Non-Utility Generation Charge (NGC)	$ 66	$ 86	Annual filing for recovery(1)(2)
Underrecovered Electric Costs BGS	12	3	Recovery on 2 month lag(1)(2)
Societal Benefits Charges (SBC)	74	53	Annual filing for recovery(1)(2)
FERC Formula True-up	3	0	Annual filing for recovery(1)(2)
Total Current Regulatory Assets	**$ 155**	**$ 142**	
Noncurrent			
Stranded Costs To Be Recovered	$ 1,776	$ 2,176	Through December 2015(1)(2)
Manufactured Gas Plant (MGP) Remediation Costs	661	694	Various(2)
Pension and Other Postretirement	953	1,053	Various
Deferred Income Taxes	402	409	Various
Remediation Adjustment Clause (RAC)	119	135	Various(2)
New Jersey Clean Energy Program	430	566	To be determined(2)
Gas Contract Mark-to-Market	50	112	Various(1)
OPEB Costs	39	58	Through December 2012(2)
Unamortized Loss on Reacquired Debt and Debt Expense	102	106	Over remaining debt life(1)
Conditional Asset Retirement Obligation	72	64	Various
Repair Allowance Taxes	27	37	Through August 2013(1)(2)
Uncertain Tax Positions	0	55	Various
Regulatory Restructuring Costs	13	18	Through August 2013(1)(2)
Gas Margin Adjustment Clause	44	45	To be determined(2)
Customer Care System	20	38	Through July 2014
Plant and Regulatory Study Costs	9	11	Through December 2021(2)
Incurred But Not Reported Claim Reserve	14	16	Various
Asbestos Abatement	7	8	Through 2020(2)
Cape May Street Cleanup	8	0	To be determined
Renewables & Energy Efficiency	96	16	Various(2)
Storm Damage	8	0	To be determined
Other	14	10	Various
Total Noncurrent Regulatory Assets	**$ 4,864**	**$ 5,627**	
Total Regulatory Assets	**$ 5,019**	**$ 5,769**	

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	As of December 31, 2010	2009	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current:			
Market Transition Charge Refund, net	$ 58	$ 0	Through December 2011(1)(2)
Deferred Income Taxes	46	52	Through November 2011
Overrecovered Gas Costs BGSS	40	45	Annual filing for recovery(1)(2)
Overrecovered Electric Costs BGS	0	41	Recovery on 2 month lag(1)(2)
Renewables & Energy Efficiency	7	9	Annual filing for recovery(1)(2)
Excess Cost of Removal	11	0	Recovery ends November 2011
Capital Stimulus Overcollection	5	4	Annual filing for recovery(1)(2)
FERC Formula True-up	5	3	Annual filing for recovery(1)(2)
BGS Retail Adder	2	2	Paid to New Jersey quarterly(2)
Current Regulatory Liabilities	**$ 174**	**$ 156**	
Non-Current:			
Electric Cost of Removal	$ 244	$ 265	Reduced as cost is incurred
Market Transition Charge Refund, net	26	0	January - June 2012
Excess Cost of Removal	0	24	Five year amortization(2)
Gas Weather Normalization Deferral	9	0	Annual filing for recovery(1)(2)
Other	14	11	Various (1)
Total Noncurrent Regulatory Liabilities	**$ 293**	**$ 300**	
Total Regulatory Liabilities	**$ 467**	**$ 456**	

(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:

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.

Overrecovered/Underrecovered Electric Energy Costs: These costs represent the overrecovered/underrecovered amounts associated with Basic Generation Service (BGS), as approved by the BPU.

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) 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.

FERC Formula True-up: Over or under collection of transmission earnings calculated using a FERC approved formula.

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.

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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.

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 RAC clause in the 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: These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices. Accordingly, the 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. The Regulatory Liability is offset by a deferred tax asset and is expected to be refunded, without interest, within the next twelve months.

Remediation Adjustment Clause: Costs incurred to clean up manufactured gas plants.

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.

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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 PSE&G s legacy customer accounting system in March 2009.

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.

Cape May Street Cleanup: Estimated cost for environmental remediation of a company owned site. Recovery will be sought from the BPU.

Renewables & Energy Efficiency: These costs are the overrecovered or underrecovered amounts associated with various renewable energy and energy efficiency programs.

Storm Damage: Costs incurred in the cleanup of 2010 storm for which recovery will be sought from the BPU.

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.

Market Transmission Charge Refund (MTC), net: These costs represent the overrecovered amounts associated with MTC.

Overrecovered/Underrecovered Gas Costs: These costs represent the overrecovered/underrecovered 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.

Capital Stimulus Overcollection: BPU approved collection of costs related to distribution projects.

BGS Retail Adder: Charge included in the BGS tariff rate to induce customer shopping.

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.

Gas Weather Normalized Deferral: This represents the overcollection due to colder than normal weather under the gas weather normalization clause which was implemented in 2010 to remove gas earnings volatility caused by variations in weather.

Other Regulatory Liabilities: This includes the following: 1) amounts collected from customers in order for Transition Funding to obtain a AAA rating on its transition bonds; 2) third party billing discounts related to the Competition Act; and 3) uncertain tax positions.

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Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2010 and 2009 included the following:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Power		
Partnerships and Corporate Joint Ventures	$ 25	$ 36
PSE&G		
Life Insurance and Supplemental Benefits	161	156
Solar Loan Investment	62	41
Other Investments	7	7
Energy Holdings		
Leases	1,255	1,609
Partnerships and Corporate Joint Ventures	112	183
Other Investments	1	0
Total Long-Term Investments	**$ 1,623**	**$ 2,032**

Leases

The net investment in leases was comprised of the following:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Lease receivables (net of non-recourse debt)	$ 896	$ 1,587
Estimated residual value of leased assets	905	934
	1,801	2,521
Unearned and deferred income	(546)	(912)
Total investments in leases	1,255	1,609
Deferred tax liabilities	(899)	(1,313)
Net investment in leases	**$ 356**	**$ 296**

The pre-tax income and income tax effects related to investments in leases were as follows:

	Years Ended December 31, 2010	2009	2008
	Millions		

Pre-tax income (loss) of leases	$ 45	$ 23	$ (408)
Income tax expense (benefit) on pre-tax income of leases	$ 14	$ 23	$ (98)

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 $105 million and $176 million as of December 31, 2010 and 2009, respectively. The decrease of $71 million between the December 31, 2010 and 2009 equity investment balances was due primarily to the sale of the equity investment in GWF Energy and the impairment of our equity investment in GWF Power in 2010. During the three years ended December 31, 2010, 2009 and 2008, the amount of dividends from these investments was $5 million, $10 million and $25 million, respectively. Energy Holdings share of income and cash flow distribution percentages ranged from 40% to 50% as of December 31, 2010.

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Power and Energy Holdings had the following equity method investments as of December 31, 2010:

	Location	% Owned
Power		
Keystone Fuel, LLC	PA	23%
Conemaugh Fuel, LLC	PA	23%
Energy Holdings		
Kalaeloa	HI	50%
GWF	CA	50%
Hanford L. P. (Hanford)	CA	50%
Bridgewater	NH	40%
Turboven	Venezuela	50%

Note 8. Financing Receivables

Energy Holdings had a net investment in leases of $356 and $296 million as of December 31, 2010 and 2009, respectively (See Note 7. Long-Term Investments). The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. Not Rated counterparties relate to investments in leases of commercial real estate properties.

Counterparties Credit Rating (S&P)	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2010	2009
AAA - AA	$ 21	$ 688
A	112	112
BBB - BB	316	316
B	430	452
Not Rated	17	19
	$ 896	**$ 1,587**

The ratings in the table above represent the ratings of the entities providing payment assurance to the subsidiary of PSEG Resources, L.L.C.(Resources).

The single B receivables represent lease receivables underlying coal, gas and oil fired assets in Illinois, New York, and Pennsylvania leased to various entities where a subsidiary of Resources is the equity lessor. As of December 31, 2010, gross investment in the leases of such assets was $811 million and the lease investment, net of deferred taxes was $148 million. A more detailed description of such assets under lease is as follows:

Asset	Location	Total Capacity (MW)	Fuel Type	Counterparty
Powerton Station	IL	1,538	Coal	Edison Mission Energy
Joliet Station	IL	1,044	Coal	Edison Mission Energy

Danskammer Station	NY	370	Coal	Dynegy Holdings Inc.
Roseton Station	NY	1,200	Gas/Oil	Dynegy Holdings Inc.
Keystone Station	PA	1,711	Coal	GenOn REMA LLC*
Conemaugh Station	PA	1,711	Coal	GenOn REMA LLC*
Shawville Station	PA	603	Coal	GenOn REMA LLC*

* formerly RRI Energy

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The credit exposure to the lessors 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 coverage ratios 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 the event of a default in any of the lease transactions, 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 foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities.

Although all payments of equity rent, debt service and other fees are current, no assurances can be given that all payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, overall financial condition of lease counterparties, and the quality and condition of assets under lease.

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout our electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECS) generated from the installed solar electric system. The following table reflects the outstanding short and long-term loans by class of customer, none of which would be considered non-performing.

Credit Risk Profile Based on Payment Activity

	As of December 31,	
Consumer Loans	**2010**	**2009**
Performing		
Commercial/Industrial	$ 62	$ 41
Residential	4	1
	$ 66	**$ 42**

Note 9. 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 an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust 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, 2010 was approximately $220 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2010			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 525	$ 213	$ (3)	$ 735
Debt Securities				
Government Obligations	301	6	(4)	303
Other Debt Securities	247	10	(2)	255
Total Debt Securities	548	16	(6)	558
Other Securities	70	0	(0)	70
Total Available-for-Sale Securities	**$ 1,143**	**$ 229**	**$ (9)**	**$ 1,363**

	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	0	(1)	36
Total Available-for-Sale Securities	**$ 1,017**	**$ 194**	**$ (12)**	**$ 1,199**

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, 2010				As of December 31, 2009			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized	Fair Value	Gross Unrealized	Fair Value	Gross Unrealized	Fair Value	Gross Unrealized

		Losses		Losses		Losses		Losses
Equity Securities(A)	$ 55	$ (3)	$ 0	$ 0	$ 61	$ (5)	$ 0	$ 0
Debt Securities								
Government Obligations(B)	106	(4)	1	0	78	(2)	15	(1)
Other Debt Securities(C)	65	(1)	8	(1)	59	(3)	0	0
Total Debt Securities	171	(5)	9	(1)	137	(5)	15	(1)
Other Securities	0	0	0	0	1	(1)	0	0
Total Available-for-Sale Securities	**$ 226**	**$ (8)**	**$ 9**	**$ (1)**	**$ 199**	**$ (11)**	**$ 15**	**$ (1)**

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(A) Equity Securities Investments in marketable equity securities within the NDT funds 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, 2010.

(B) Debt Securities (Government) Unrealized losses on Power s NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since 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, 2010.

(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 for 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, 2010.

The proceeds from the sales of and the net realized gains on securities in the NDT Funds were:

	Years Ended December 31,		
	2010	**2009**	**2008**
		Millions	
Proceeds from Sales	**$ 958**	**$ 1,769**	**$ 3,060**
Net Realized Gains:			
Gross Realized Gains	$ 119	$ 183	$ 354
Gross Realized Losses	(39)	(135)	(273)
Net Realized Gains	**$ 80**	**$ 48**	**$ 81**

Net realized gains disclosed in the above table were recognized in Other Income and Other Deductions in Power s Consolidated Statements of Operations. Net unrealized gains of $109 million (after-tax) were recognized in Accumulated Other Comprehensive Loss in Power s Consolidated Balance Sheet as of December 31, 2010.

The available-for-sale debt securities held as of December 31, 2010 had the following maturities:

Time Frame	**Fair Value**
	Millions
Less than one year	$ 16
1 - 5 years	103
6 - 10 years	162
11 - 15 years	39
16 - 20 years	6
Over 20 years	232
	$ 558

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

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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 (Loss). In 2010, other-than-temporary impairments of $9 million were recognized on securities in the NDT Funds. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be 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 of the securities.

Rabbi Trusts

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a Rabbi Trust. In August 2010, PSEG revised the asset structure of the Rabbi Trust and realized gains of approximately $31 million as the investments were transitioned to a new asset allocation and investment manager. The new structure is expected to result in lower investment management fees.

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, 2010			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 16	$ 2	$ 0	$ 18
Debt Securities	142	0	0	142
Other Securities	0	0	0	0
Total PSEG Available-for-Sale Securities	**$ 158**	**$ 2**	**$ 0**	**$ 160**

	As of December 31, 2009			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 10	$ 3	$ 0	$ 13
Debt Securities	101	21	0	122
Other Securities	14	0	0	14
Total PSEG Available-for-Sale Securities	**$ 125**	**$ 24**	**$ 0**	**$ 149**

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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 2010, other-than-temporary impairments of $2 million were recognized on the investments of the Rabbi Trusts.

	Years Ended December 31,		
	2010	2009	2008
		Millions	
Proceeds from Sales	**$ 158**	**$ 2**	**$ 23**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 31	$ 0	$ 2
Gross Realized Losses	0	(1)	(2)
Net Realized Gains (Losses)	**$ 31**	**$ (1)**	**$ 0**

The cost of these securities was determined on the basis of specific identification.

The estimated fair value of the Rabbi Trusts related to PSEG, Power and PSE&G are detailed as follows:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Power	$ 32	$ 30
PSE&G	54	51
Other	74	68
Total PSEG Available-for-Sale Securities	**$ 160**	**$ 149**

Note 10. Goodwill and Other Intangibles

As of each of December 31, 2010 and 2009, Power had goodwill of $16 million related to the Bethlehem Energy Center. Power conducted an annual review for goodwill impairment as of October 31, 2010 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

In addition to goodwill, as of December 31, 2010 and 2009, Power had intangible assets of $130 million and $114 million, respectively, related to emissions allowances and renewable energy credits. See Note 17. Fair Value Measurements for additional information regarding impairments to emission allowances. Emissions expense includes costs for CO_2 emissions, which is recorded as emissions occur. Expense related to renewable energy requirements is recorded as load is served under contracts requiring energy from renewable sources. Such expenses for the years ended December 31, 2010, 2009 and 2008 were as follows:

Years Ended December 31,

	2010	2009	2008
		Millions	
Emissions Expense	$ 52	$ 34	$ 1
Renewable Energy Expense	$ 50	$ 46	$ 25

Also as of December 31, 2010 and 2009, Energy Holdings joint venture that develops compressed air energy storage had intangible assets of $8 million and $9 million, respectively.

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Note 11. Asset Retirement Obligations (AROs)

PSEG, Power and PSE&G have recorded various 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. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. 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.

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.

The changes to the ARO liabilities for PSEG, Power and PSE&G during 2010 are presented in the following table:

	PSEG	Power	PSE&G	Other
		Millions		
ARO Liability as of January 1, 2010	$ 439	$ 226	$ 211	$ 2
Liabilities Settled	(11)	(2)	(9)	0
Liabilities Incurred	2	0	1	1
Accretion Expense	18	18	0	0
Accretion Expense Deferred and Recovered in Base Rates (A)	13	0	13	0
ARO Liability as of December 31, 2010	**$ 461**	**$ 242**	**$ 216**	**$ 3**

(A) Not reflected as expense in Consolidated Statements of Operations

Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB 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 of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. 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,

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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 Income (Loss), a separate component of Stockholders 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 Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

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, 2010 and 2009. 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	
	2010	**2009**	**2010**	**2009**
	Millions			
Change in Benefit Obligation:				
Benefit Obligation at Beginning of Year	$ 4,017	$ 3,569	$ 1,255	$ 1,104
Service Cost	87	76	16	13
Interest Cost	231	235	72	73
Actuarial (Gain) Loss	242	381	58	129
Gross Benefits Paid	(224)	(216)	(72)	(69)
Medicare Subsidy Receipts	0	0	4	5
Plan Amendments	0	(28)	(171)	0
Benefit Obligation at End of Year	**$ 4,353**	**$ 4,017**	**$ 1,162**	**$ 1,255**
Change in Plan Assets:				
Fair Value of Assets at Beginning of Year	$ 2,914	$ 2,364	$ 160	$ 129
Actual Return on Plan Assets	441	393	24	20
Employer Contributions	424	373	79	75
Gross Benefits Paid	(224)	(216)	(72)	(69)
Medicare Subsidy Receipts	0	0	4	5
Fair Value of Assets at End of Year	**$ 3,555**	**$ 2,914**	**$ 195**	**$ 160**
Funded Status:				
Funded Status (Plan Assets less Benefit Obligation)	**$ (798)**	**$ (1,103)**	**$ (967)**	**$ (1,095)**
Additional Amounts Recognized in the Consolidated Balance Sheets:				
Current Accrued Benefit Cost	$ (10)	$ (9)	$ 0	$ 0
Noncurrent Accrued Benefit Cost	(788)	(1,094)	(967)	(1,095)
Amounts Recognized	**$ (798)**	**$ (1,103)**	**$ (967)**	**$ (1,095)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets:				
Net Transition Obligation	$ 0	$ 0	$ 15	$ 57

Prior Service Cost	(3)	(3)	(85)	83
Net Actuarial Loss	1,562	1,617	212	172
Total	**$ 1,559**	**$ 1,614**	**$ 142**	**$ 312**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2010, PSEG has funded approximately 82% of its projected benefit obligation. This percentage does not include $160 million of assets in the Rabbi Trusts as of December 31, 2010, 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 $3.9 billion as of December 31, 2010 and $3.6 billion as of December 31, 2009.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
	Millions					
Components of Net Periodic Benefit Cost:						
Service Cost	$ 87	$ 76	$ 78	$ 16	$ 13	$ 15
Interest Cost	231	235	227	72	73	72
Expected Return on Plan Assets	(266)	(215)	(290)	(14)	(12)	(15)
Amortization of Net						
Transition Obligation	0	0	0	27	27	27
Prior Service Cost	0	7	9	13	13	13
Actuarial Loss	122	113	13	8	(2)	(1)
Net Periodic Benefit Cost	**$ 174**	**$ 216**	**$ 37**	**$ 122**	**$ 112**	**$ 111**
Effect of Regulatory Asset	0	0	0	19	19	19
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 174**	**$ 216**	**$ 37**	**$ 141**	**$ 131**	**$ 130**

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,		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
	Millions					
Power	$ 54	$ 65	$ 10	$ 17	$ 11	$ 13
PSE&G	97	120	16	120	116	113
Other	23	31	11	4	4	4
Total Benefit Costs	**$ 174**	**$ 216**	**$ 37**	**$ 141**	**$ 131**	**$ 130**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2010	2009	2010	2009
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 67	$ 203	$ 48	$ 120
Amortization of Net Actuarial Gain (Loss)	(122)	(113)	(8)	3
Prior Service Credit in Current Period	0	(28)	(171)	0
Amortization of Prior Service Credit	0	(7)	(13)	(13)
Amortization of Transition Asset	0	0	(27)	(27)
Total	**$ (55)**	**$ 55**	**$ (171)**	**$ 83**

Amounts that are expected to be amortized from Accumulated OCL, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2011 are as follows:

	Pension Benefits 2011	Other Benefits 2011
	Millions	
Actuarial (Gain) Loss	$ 122	$ 14
Prior Service Cost	$ 0	$ (12)
Transition Obligation	$ 0	$ 7

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2010	2009	2008	2010	2009	2008
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31:						
Discount Rate	5.51%	5.91%	6.80%	5.50%	5.90%	6.80%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31:						
Discount Rate	5.91%	6.80%	6.50%	5.90%	6.80%	6.50%
Expected Return on Plan Assets	8.50%	8.75%	8.75%	8.50%	8.75%	8.75%
Rate of Compensation Increase	4.61%	4.61%	4.69%	4.61%	4.61%	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				7.75%	8.50%	8.50%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2015	2015	2013
Post-65 Medical Costs						
Immediate Rate				8.75%	9.50%	9.50%

Ultimate Rate	5.00%	5.00%	5.00%
Year Ultimate Rate Reached	2016	2016	2014

Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs:

		Millions	
Total of Service Cost and Interest Cost	$ 10	$ 11	$ 10
Postretirement Benefit Obligation	$ 122	$ 137	$ 111

Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs:

Total of Service Cost and Interest Cost	$ (8)	$ (9)	$ (8)
Postretirement Benefit Obligation	$ (102)	$ (115)	$ (93)

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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 17. 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 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, 2010, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 95% and 5%, respectively.

The following tables present information about the investments measured at fair value on a recurring basis at December 31, 2010 and 2009, including the fair value measurements and the levels of inputs used in determining those fair values.

		Recurring Fair Value Measurments as of December 31, 2010		
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds(A)	$ 118	$ 0	$ 95	$ 23
Common Stocks(B)				
Commingled US	1,568	1,568	0	0
Commingled International	696	696	0	0
Other	352	352	0	0
Bonds(C)				
Commingled US	8	0	0	8
Government (US & Foreign)	378	0	378	0
Other	544	0	544	0
Pooled Real Estate(D)	48	0	0	48
Private Equity(E)	38	0	0	38
	$ 3,750	**$ 2,616**	**$ 1,017**	**$ 117**

		Recurring Fair Value Measurments 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		
Temporary Investment Funds(A)	$ 116	$ 0	$ 63	$ 53
Common Stocks(B)				
Commingled US	1,285	1,285	0	0
Commingled International	474	474	0	0
Other	251	251	0	0
Bonds(C)				
Commingled US	17	0	0	17

Commingled International	11	0	0	11
Government (US & Foreign)	312	0	312	0
Other	469	0	469	0
Pooled Real Estate(D)	102	0	0	102
Private Equity(E)	37	0	0	37
	$ 3,074	**$ 2,010**	**$ 844**	**$ 220**

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(A) Certain 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 temporary investment funds 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. 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 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).

Reconciliations of the beginning and ending balances of the Pension and OPEB Plans Level 3 assets for the years ended December 31, 2010 and 2009 follow:

	Balance as of January 1, 2010	**Purchases/ (Sales)**	**Actual Return on Asset Sales**	**Actual Return on Assets Still Held**	**Balance as of December 31, 2010**
			Millions		
Temporary Investment Funds	$ 53	$ (30)	$ 0	$ 0	$ 23
Commingled Bonds US	$ 17	$ (11)	$ 1	$ 1	$ 8
Commingled Bonds International	$ 11	$ 0	$ (11)	$ 0	$ 0
Pooled Real Estate	$ 102	$ (53)	$ (29)	$ 28	$ 48
Private Equity	$ 37	$ (7)	$ 5	$ 3	$ 38

	Balance as of	**Purchases/ (Sales)**	**Actual Return on Asset Sales**	**Actual Return on Assets Still**	**Balance**

	January 1, 2009			Held	as of December 31, 2009
			Millions		
Temporary Investment Funds	$ 25	$ 28	$ 0	$ 0	$ 53
Commingled Bonds US	$ 348	$ (352)	$ 29	$ (8)	$ 17
Commingled Bonds International	$ 10	$ 2	$ 0	$ (1)	$ 11
Pooled Real Estate	$ 171	$ 4	$ 0	$ (73)	$ 102
Private Equity	$ 40	$ (2)	$ 1	$ (2)	$ 37

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There were no transfers among levels during the years ending December 31, 2010 and 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:

Investments	As of December 31, 2010	2009
Equity Securities	70%	66%
Fixed Income Securities	25%	26%
Real Estate Assets	1%	3%
Other Investments	4%	5%
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 8.50% as of December 31, 2010 and will remain at 8.50% for 2011. 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 9.36%.

Plan Contributions

PSEG may contribute up to $415 million into its pension plans and $11 million into its postretirement healthcare plan for calendar year 2011.

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 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	Other Benefits Gross OPEB	Other Benefits Medicare Subsidy	Net OPEB
	Millions			
2011	$ 238	$ 81	$ (5)	76
2012	244	83	(6)	77
2013	252	73	0	73
2014	260	73	0	73
2015	270	73	0	73
2016-2020	1,533	368	0	368

Total	**$ 2,797**	**$ 751**	**$ (11)**	**$ 740**

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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.

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 qualified final average pay pension plan were 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.

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,		
	2010	**2009**	**2008**
		Millions	
Power	$ 5	$ 10	$ 9
PSE&G	9	17	17
Other	3	5	5
Total Employer Matching Contributions	**$ 17**	**$ 32**	**$ 31**

Note 13. 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.

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).

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Power believes the probability of this result is unlikely. For this reason, Power believes that 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 collateral 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 collateral requirements under such contracts, which are posted and received primarily in the form of cash and 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, 2010 and 2009 are shown below:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Face Value of Outstanding Guarantees	$ 1,936	$ 1,783
Exposure under Current Guarantees	$ 330	$ 403
Letters of Credit Margin Posted	$ 137	$ 122
Letters of Credit Margin Received	$ 109	$ 123
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ 0	$ 0
Counterparty Cash Margin Received	(2)	(90)
Net Broker Balance Received	(28)	(31)
In the event Power were to lose its investment grade rating:		
Additional Collateral that could be Required	$ 828	$ 986
Liquidity Available under PSEG s and Power s Credit Facilities to Post Collateral	$ 2,750	$ 2,368
Additional Amounts Posted		
Other Letters of Credit	$ 98	$ 52

Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. 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 further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Environmental Matters

Passaic River

Historic operations by PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers 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 an eight-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 has determined the need to perform a study of 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 Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former 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, currently 69 members, 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 proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the study is not subject to the cost sharing agreement discussed above. A revised focused feasibility study may be released as early as the second quarter of 2011.

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 both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. 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 and the Newark Bay Complex. 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 filed answers to the complaint in June 2010. A special master for discovery has been appointed by the court. 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 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees claims can be resolved in a cooperative fashion. That effort is continuing.

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. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the next phase.

PSEG, Power and PSE&G cannot predict what further actions, if any, or the costs or the timing thereof, 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 ten most significant sites for cleanup. One of the sites identified was PSE&G s former Camden Coke facility.

During the third quarter of 2010, PSE&G updated the estimated cost to remediate all MGP sites to completion and determined that the cost to completion could range between $668 million and $774 million from September 30, 2010 through 2021. Since no amount within the range was considered to be most likely, PSE&G reflected a liability of $668 million on its Consolidated Balance Sheet as of September 30, 2010. During the fourth quarter of 2010, PSE&G had $7 million of expenditures, reducing the liability to $661 million as of December 31, 2010. Of this amount, $52 million was recorded in Other Current Liabilities and $609 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $661 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 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.

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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 the Hudson and Mercer facilities designed to meet targeted reductions in emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter and mercury. Power completed the construction of all plant modifications by the end of 2010 at a cost of $1.3 billion. Performance testing to validate the agreed-upon emission reductions is ongoing.

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 completed 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

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.

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 Maximum Available Control Technology (MACT) process. In 2009, the Commonwealth Court of Pennsylvania struck down the state rule, indicating that the rule violated Pennsylvania law because it was inconsistent with the Clean Air Act. In December 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 Pennsylvania Department of Environmental Protection, then our Pennsylvania generating stations likely will be subject to regulation under a MACT rule which the EPA indicated that it will finalize by November 2011. It is uncertain whether the Keystone and Conemaugh generating stations will be able to achieve the necessary reductions under MACT regulation at these stations with currently planned capital projects.

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 has a significant impact on Power s generation fleet, as it imposes NO_x emissions limits that will require significant capital investment for controls or 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 to address the retirement of electric generation units. Power cannot predict the financial impact resulting from compliance with this rulemaking.

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Connecticut

Under current Connecticut regulations, Power s Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities operating permits. On April 30, 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

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 related to these obligations, which was included in Environmental Costs on Power s and PSEG s Consolidated Balance Sheets as of December 31, 2010 and December 31, 2009.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), New Jersey Pollutant Discharge Elimination System (NJPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a 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 applications for permits in a variety of states.

One of the most significant NJPDES 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 316(b) rules published in 2004. Those rules did not mandate the use of cooling towers at large existing generating plants. Rather, the rules 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.

As a result of several challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a January 2007 U.S. Court of Appeals for the Second Circuit decision, as modified by an April 2009 United States Supreme Court decision. In sum, 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. In April 2009, the U.S. Supreme Court reversed the Second Circuit s opinion concerning the cost-benefit test, 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.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule. Pursuant to the settlement agreement, the EPA is to propose a rule no later than March 14, 2011, and issue a final rule by July 27, 2012. Until a new rule governing cooling water intake structures at existing power generating stations is finalized, the 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.

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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. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power s forecasted capital expenditures.

In addition to the anticipated EPA rulemaking, several states, including California and New York, have begun setting policies that may require closed cycle cooling. It is unknown how these policies will ultimately impact the EPA s rulemaking.

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. In December 2010, NJDEP and that company entered into an Administrative Consent Order (ACO) which would require the company to cease operations at the nuclear generating station no later than 2019. In the ACO, the NJDEP agreed that closed cycle cooling is not the best technology available for the facility and agreed to issue a new draft NJPDES permit for that facility without a requirement for construction of cooling towers or other closed cycle cooling facilities. The new draft NJPDES permit will be issued in substitution for the draft NJPDES permit issued in January 2010. We cannot predict at this time the final outcome of the NJDEP 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 has determined that Hudson is no longer eligible to utilize this general permit.

In December 2010, the NJDEP issued a draft renewal NJPDES permit to Power which, among other things, proposed conditions regarding stormwater runoff from the Hudson coal pile. The NJDEP authorized a new discharge of stormwater runoff without further requirement to construct technologies preventing the discharge of stormwater to surface water or groundwater. The draft permit is subject to public comment. It is unclear when the NJDEP will issue a final NJPDES permit. To the extent the NJDEP reverses course and requires elimination of the exposure of coal to stormwater, or requires new technologies to prevent the discharge of stormwater to surface 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 its co-owned 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, 2010 were $47 million and are expected to continue through 2012.

Power has begun expenditures in pursuit of additional output through an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Power s share of the increased capacity is expected to be 133 MW with an anticipated cost of approximately $400 million. Total expenditures through December 31, 2010 were $18 million and are expected to continue through 2016.

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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 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 $130 million to $140 million. Total capitalized expenditures through December 31, 2010 were $46 million, which are included in Property, Plant and Equipment on the Consolidated Balance Sheets of PSEG and Power.

PJM Interconnection L.L.C. (PJM)

Power plans to construct gas fired peaking facilities at its Kearny site. Capacity in the amount of 178 MW was bid into and cleared the PJM Reliability Pricing Model (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. In addition, capacity in the amount of 89 MW was bid into and cleared the PJM RPM base residual capacity auction for the 2013-2014 period. Final approval has been received, and the project is expected to be in service by June 2012. Power estimates the cost of these generating units to be $250 million to $300 million. Total capitalized expenditures through December 31, 2010 were $46 million which are included in Property, Plant and Equipment on Power s and PSEG s Consolidated Balance Sheets.

PSE&G Solar

As part of the BPU-approved Solar 4 All Program, PSE&G is installing up to 40 MW of solar generation on existing utility poles within its service territory. PSE&G has entered into an agreement to purchase solar units for this program. PSE&G s commitments under this agreement are contingent upon, among other things, the availability of suitable utility poles for installation of the units. Approximately 15 MW have been installed as of December 31, 2010. PSE&G s cumulative investments for these solar units were approximately $110 million, with additional purchases to be made on a quarterly basis during the remaining two-year term of the purchase agreement.

Another aspect of the Solar 4 All program is the installation of another 40 MW of solar systems on land and buildings owned by PSE&G and third parties. During 2010, 13 MW representing 11 projects were placed into service with an investment of approximately $70 million.

Solar Source

Energy Holdings has developed a solar project in western New Jersey and has acquired two additional solar projects in Florida and Ohio, which together have a total capacity of approximately 29 MW. The projects have all commenced operations. Energy Holdings issued guarantees to cover the construction costs of the Florida and Ohio projects and as of December 31, 2010 had $2 million of payment obligations related to final acceptance. The total investment for the three projects was approximately $117 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 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

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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			
	2008	**2009**	**2010**	**2011**
36-Month Terms Ending	May 2011	May 2012	May 2013	May 2014(A)
Load (MW)	2,800	2,900	2,800	2,800
$ per kWh	0.11150	0.10372	0.09577	0.09430

(A) Prices set in the 2011 BGS auction will become effective on June 1, 2011 when the 2008 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 23. Related-Party Transactions. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements.

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 in inventory and to make periodic purchases to support such levels. As such, the commitments referred to below may include estimated quantities to be purchased that deviate from contractual nominal quantities.

Power s nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2012 and a portion for 2013, 2014 and 2015 at Salem, Hope Creek and Peach Bottom.

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As of December 31, 2010, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Commitments through 2015 Power s Share	
		Millions
Nuclear Fuel		
Uranium	$	390
Enrichment	$	366
Fabrication	$	129
Natural Gas	$	885
Coal	$	1,179

Included in the $1,179 million commitment for coal, is $681 million related to a certain coal contract under which Power can cancel contractual deliveries at minimal cost. In 2010, Power cancelled coal shipments at a total cost of $16 million, primarily consisting of freight cancellation charges.

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.

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. In June 2010, the BPU granted PSE&G s motion to dismiss. PSE&G has not yet received the written order from the BPU memorializing its decision.

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 addressed SBC, MTC and non-utility generation (NUG) deferred balances, found that the Phase II deferral balances complied in all material respects with applicable BPU Orders. However, the BPU Staff 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.

In June 2010, the BPU approved a settlement agreement resolving the MTC issue. Under the agreement, PSE&G will refund $122 million to electric customers over a two-year period through a new component of the NUG charge. As a result, during the second quarter of 2010, PSE&G recorded a pre-tax charge of $122 million, which is included in Operating Revenues and the corresponding Regulatory Liability.

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Retail Gas Transportation Rates

In July 2010, as part of PSE&G s gas base rate proceeding, the BPU ordered a supplemental and expedited review of certain issues related to the gas transportation rate that PSE&G charges to Power.

Also in July, a complaint was filed by an independent power generator against Power at FERC related to the gas transportation rate.

In December 2010, the BPU approved a settlement that resolves all remaining issues in PSE&G s base rate case.

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 is $705 million. PSE&G has recorded a discounted liability of $430 million as of December 31, 2010. Of this amount, $195 million was recorded as a current liability and $235 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 IRS has issued reports with respect to its audits of PSEG s consolidated 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 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 pursued opportunities to terminate international leases with lessees that were willing to meet certain economic thresholds. As of December 31, 2010, Energy Holdings has terminated all of these leasing transactions and reduced the related cash tax exposure by $1.1 billion. PSEG has completely eliminated its gross investment in such transactions, which is a decrease from December 31, 2009 of $347 million.

Cash Impact

As of December 31, 2010, an aggregate of approximately $260 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, eliminating its cash exposure completely. In the event PSEG is successful in defense of its position, the deposit is fully refundable with interest. 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 an average rate of $2 million per quarter during 2011. 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 $20 million to $40 million of tax would be due for tax positions through December 31, 2010.

Unless this matter is resolved with the IRS, PSEG currently anticipates that it may be required to pay between $110 million and $300 million in tax, interest and penalties for the tax years 1997-2000 during 2011 and subsequently commence litigation to recover those amounts. It is possible that an additional payment of between $210 million and $540 million could be required during 2011 for tax years 2001-2003 followed by further litigation to recover those amounts. The amounts that may be required to litigate differ from the potential net cash exposure noted above, as the former amounts include all potential deficiencies for only

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contested tax years 1997 through 2003. These litigation amounts also include penalties which are not included in the computation of potential net cash exposure as PSEG believes it has strong defenses. These amounts also exclude an offset for taxes paid on lease terminations, which is netted in the potential net cash exposure as PSEG would be entitled to a refund of such amounts under a loss scenario. Any potential claims PSEG would make to recover such amounts would include the deposit noted above.

Earnings Impact

PSEG s current reserve position represents its 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 $120 million to $140 million.

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.

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.

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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)	$ 0
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 hazard of nuclear radiation. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(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.

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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, 2010 are:

	Power	Other
	Millions	
2011	$ 1	$ 8
2012	2	7
2013	2	7
2014	2	7
2015	1	6
Thereafter	0	0
Total Minimum Lease Payments	**8**	**35**
Less: Imputed Interest	(1)	(9)
Present Value of Net Minimum Lease Payments	**$ 7**	**$ 26**

PSE&G has leased administrative office space under various operating leases. Total future minimum lease payments as of December 31, 2010 are $11 million.

Note 14. Schedule of Consolidated Debt

Long-Term Debt

	As of December 31,	
	2010	**2009**
	Millions	
PSEG (Parent)		
Fair Value of Swaps(A)	39	(3)
Unamortized Discount Related to Debt Exchange(B)	(29)	(35)
Total Long-Term Debt of PSEG (Parent)	**$ 10**	**$ (38)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2010	2009
		Millions	
Power			
Senior Notes:			
7.75%	2011	$ 606	$ 800
6.95%	2012	600	600
2.50%	2013	300	0
5.00%	2014	250	250
5.50%	2015	300	300
5.32%	2016	303	303
5.13%	2020	406	0
8.63%	2031	500	500
Total Senior Notes		3,265	2,753
Pollution Control Notes:			
Floating Rate (C)	2011	44	0
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
Total Pollution Control Notes		208	164
Medium Term Notes (MTNs):			
6.00%	2013	0	48
6.50%	2014	0	161
Total MTNs		0	209
Principal Amount Outstanding		3,473	3,126
Amounts Due Within One Year		(650)	0
Net Unamortized Discount		(18)	(5)
Total Long-Term Debt of Power		**$ 2,805**	**$ 3,121**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2010	2009
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (D):			
Libor + .875%	2010	$ 0	$ 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		320	620
Pollution Control Bonds (D):			
5.20%	2025	23	23
0.95%(E)	2028 - 2033	164	0
1.2%(E)	2031	100	0
5.45%	2032	50	50
6.40%	2032	0	100
Total Pollution Control Bonds		337	173
Medium-Term Notes (D):			
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
2.70%	2015	300	0
5.30%	2018	400	400
7.04%	2020	9	9
3.50%	2020	250	0
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	0
Total MTNs		3,634	2,784
Principal Amount Outstanding		4,291	3,577
Amounts Due Within One Year		(264)	(300)
Net Unamortized Discount		(8)	(6)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**$ 4,019**	**$ 3,271**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2010	2009
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.45%	2009-2011	46	232
6.61%	2009-2013	454	454
6.75%	2009-2014	220	220
6.89%	2009-2015	370	370
Principal Amount Outstanding		1,090	1,276
Amounts Due Within One Year		(195)	(186)
Total Securitization Debt of Transition Funding		**895**	**1,090**
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.34%	2009-2012	12	24
4.49%	2009-2013	20	20
4.57%	2009-2015	23	23
Principal Amount Outstanding		55	67
Amounts Due Within One Year		(11)	(12)
Total Securitization Debt of Transition Funding II		**44**	**55**
Total Long-Term Debt of PSE&G		**$ 4,958**	**$ 4,416**

Energy Holdings	Maturity	As of December 31, 2010	2009
		Millions	
8.5% Senior Notes	2011	$ 0	$ 127
Non-Recourse Project Debt(F):			
Resources - 4.75% to 8.75%	2010-2020	46	30
EGDC - 8.27%	2009-2013	1	12
Principal Amount Outstanding		47	42
Amounts Due Within One Year		(1)	(23)
Total Non-Recourse Project Debt		46	19
Total Long-Term Debt of Energy Holdings		**$ 46**	**$ 146**

(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 16. Financial Risk Management Activities.

(B) 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 is being amortized over the term of the newly issued debt. The deferred amount is reflected as an offset

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

(C) The Pennsylvania Economic Development Authority (PEDFA) bond is a variable rate bond that is in weekly reset mode.

(D) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(E) Subject to mandatory put in 2011 and included in Long-Term Debt due within One Year on the Consolidated Balance Sheets as of December 31, 2010 due to the fact that PSE&G has not yet determined whether it will refinance the debt at that time. See Long-Term Debt Financing Transactions below for additional information about these transactions.

(F) 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-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.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2010 are as follows:

Year	PSEG (Parent)	Power	PSE&G	PSE&G Transition Funding	Transition Funding II	Energy Holdings Non-Recourse Debt	Total
				Millions			
2011	$ 0	$ 650	$ 264	$ 195	$ 11	$ 1	$ 1,121
2012	0	666	300	205	12	2	1,185
2013	0	300	725	214	12	1	1,252
2014	0	250	250	225	12	1	738
2015	0	300	300	251	8	17	876
Thereafter	0	1,307	2,452	0	0	25	3,784
	$ 0	**$ 3,473**	**$ 4,291**	**$ 1,090**	**$ 55**	**$ 47**	**$ 8,956**

Long-Term Debt Financing Transactions

During 2010, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

Power

issued $300 million of 2.50% unsecured Senior Notes due April 2013 in April, issued $250 million of 5.125% unsecured Senior Notes due April 2020 in April,

redeemed $161 million of 6.50% Medium-Term Notes (MTNs) due 2014 in April,

redeemed $48 million of 6.00% MTNs due 2013 in April,

exchanged an aggregate principal amount of $195 million of 7.75% Senior Notes due 2011 for $208 million comprised of $156 million in newly issued 5.125% Senior Notes due April 2020 and cash payments of $52 million. Since the debt exchange was treated as a debt modification, the resulting premium of $13 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 Power s Consolidated Balance Sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

converted $44 million of its Senior Notes servicing and securing the 4.00% Pollution Control Bonds of the PEDFA 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. 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 a letter of credit expiring in January 2011 which was extended until December 2011.

PSE&G

at PSE&G s request, the New Jersey Economic Development Authority (EDA) called $100 million of its 6.40% tax-exempt Pollution Control Revenue Refunding Bonds, 1994 Series A (Public Service Electric and Gas Company Project) due May 2032, and refinanced them with the issuance of $100 million of its Exempt Facility Revenue Refunding Bonds, 2010 Series A (Public Service Electric and Gas Project) (AMT), due December 2031 as multi-mode bonds with a mandatory put due December 2011 and an initial term rate of 1.20% in October. The EDA bonds that were redeemed were serviced and secured by PSE&G s First and Refunding Mortgage Bonds, Pollution Control Series P which were also redeemed. The new EDA bonds are serviced and secured by PSE&G s First and Refunding Mortgage Bonds, Pollution Control Series AE of similar tenor.

remarketed $64 million 2003 Series A due May 2028, $50 million 2003 Series B-1 due November 2033 and $50 million 2003 Series B-2 due November 2033, totaling $164 million, tax-exempt variable rate bonds of the Pollution Control Financing Authority of Salem County (Salem County Authority Bonds) (non-AMT) as The Pollution Control Financing Authority of Salem County Pollution Control Revenue Refunding Bonds (Public Service Electric and Gas Company Project) mandatory puts due November 2011 at an initial term rate of 0.95% in September,

issued $250 million of 3.50% MTNs, Series G due August 2020 in August,

issued $300 million of 2.70% MTNs, Series G due May 2015 in May,

redeemed all $80 million of its outstanding preferred stock in March,

paid $300 million of floating rate (Libor + .875%) First and Refunding Mortgage Bonds at maturity in March,

issued $300 million of 5.50% MTNs, Series G due March 2040 in March,

paid $186 million of Transition Funding s securitization debt, and

paid $11 million of Transition Funding II s securitization debt.

Energy Holdings

redeemed the remaining $127 million outstanding principal balance of its 8.50% Senior Notes due June 2011 in December 2010.

paid $12 million of nonrecourse project debt.

refinanced $20 million of nonrecourse project debt.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements as well as those of Power primarily through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under PSEG s credit facilities are provided by a diverse bank group. As of December 31, 2010, no single institution represented more than 11% of the total commitments in our credit facilities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2010 were as follows:

Company/Facility	Total Facility	Usage		Available Liquidity	Expiration Date	Primary Purpose
	As of December 31, 2010 (Millions)					
PSEG						
5-year Credit Facility(A)	$ 1,000	$ 77	(C)	$ 923	Dec 2012	Commercial Paper (CP) Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 77**		**$ 923**		
Power						
5-year Credit Facility(A)	$ 1,600	$ 133	(C)	$ 1,467	Dec 2012	Funding/Letters of Credit
2-year Credit Facility	350	0		350	July 2011	Funding
Bilateral Credit Facility	100	90	(C)	10	Sept 2015	Letters of Credit
Total Power	**$ 2,050**	**$ 223**		**$ 1,827**		
PSE&G						
5-year Credit Facility(B)	$ 600	$ 0		$ 600	June 2012	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 0**		**$ 600**		
Total	**$ 3,650**	**$ 300**		**$ 3,350**		

(A) In December 2011, facilities reduce by $47 million and $75 million, for PSEG and Power, respectively.

(B) In June 2011, this facility will be reduced by $28 million.

(C) Includes amounts related to letters of credit outstanding.

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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, 2010 and 2009.

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value *	Carrying Amount	Fair Value *
	Millions			
Long-Term Debt:				
PSEG (Parent)	$ 10	$ 39	$ (38)	$ (3)
Power -Recourse Debt	3,455	3,831	3,121	3,473
PSE&G	4,283	4,615	3,571	3,807
Transition Funding (PSE&G)	1,090	1,245	1,276	1,449
Transition Funding II (PSE&G)	55	59	67	71
Energy Holdings:				
Senior Notes	0	0	127	134
Project Level, Non-Recourse Debt	47	47	42	42
	$ 8,940	**$ 9,836**	**$ 8,166**	**$ 8,973**

* Excludes unamortized discount.

Note 15. Schedule of Consolidated Capital Stock and Other Securities

	Outstanding Shares	As of December 31, Book Value 2010	2009
		Millions	
PSEG Common Stock (no par value)(A)			
Authorized 1,000,000,000 shares; (outstanding as of December 31, 2009, 505,989,630 shares)	505,974,223	$ 4,214	$ 4,200

	Outstanding Shares	Redemption Price Per Share	As of December 31, Book Value 2009
			Millions
PSE&G Cumulative Preferred Stock(B) (C) without Mandatory Redemption $100 par value series			

4.08%	146,221	$ 103.00	$ 15
4.18%	116,958	$ 103.00	12
4.30%	149,478	$ 102.75	15
5.05%	104,002	$ 103.00	10
5.28%	117,864	$ 103.00	12
6.92%	160,711	$ 101.39	16
Total Preferred Stock without Mandatory Redemption	**795,234**		**$ 80**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(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 2010 or 2009. 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, 2010.

(B) In March 2010, PSE&G redeemed all of its outstanding preferred stock. As a result, all of the outstanding equity in PSE&G is owned by PSEG.

(C) As of December 31, 2010, there was an aggregate of 7.5 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 have provided for mandatory sinking fund redemption.

Note 16. 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 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. Derivative 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.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps, futures and firm transmission right (FTR) 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, 2010 and 2009, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with these hedges was as follows:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Fair Value of Cash Flow Hedges	$ 196	$ 286

Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 114	$ 184

The expiration date of the longest-dated cash flow hedge at Power is in 2012. Power s after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the 12 months ending December 31, 2011 and December 31, 2012 are $112 million and $2 million, respectively. Ineffectiveness associated with these hedges was $2 million at December 31, 2010.

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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 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 are marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) over the three year period ended December 31, 2010.

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. Changes in fair market value of these contracts are recorded in earnings. The fair value of these contracts as of December 31, 2010 and 2009 was $(4) million.

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 by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, PSEG, Power and PSE&G use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. In January 2010, we entered into a series of interest rate swaps totaling $600 million converting $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. 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 changes in the fair value of the underlying debt. In 2009, PSEG had entered into three interest rate swaps also designated as fair value hedges. As of December 31, 2010 and 2009, the fair value of all the underlying hedges was $39 million and $(3) million, respectively.

Cash Flow Hedges

PSEG, Power 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, 2010, there was no hedge ineffectiveness associated with these hedges. The total fair value of these interest rate derivatives was immaterial as of each of December 31, 2010 and 2009. The Accumulated Other Comprehensive Loss (after tax) related to interest rate derivatives designated as cash flow hedges was $(3) million and $(4) million as of each of December 31, 2010 and 2009, respectively.

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Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets:

	As of December 31, 2010						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Non Hedges Energy-Related Contracts	Netting (A)	Total Power	Non Hedges Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 204	$ 403	$ (444)	$ 163	$ 0	$ 19	$ 182
Noncurrent Assets	3	80	(41)	42	17	20	79
Total Mark-to-Market Derivative Assets	**$ 207**	**$ 483**	**$ (485)**	**$ 205**	**$ 17**	**$ 39**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (11)	$ (454)	$ 374	$ (91)	$ (12)	$ 0	$ (103)
Noncurrent Liabilities	0	(72)	50	(22)	0	0	(22)
Total Mark-to-Market Derivative (Liabilities)	**$ (11)**	**$ (526)**	**$ 424**	**$ (113)**	**$ (12)**	**$ 0**	**$ (125)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 196**	**$ (43)**	**$ (61)**	**$ 92**	**$ 5**	**$ 39**	**$ 136**

	As of December 31, 2009						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related	Non Hedges Energy-Related	Netting * (A)	Total Power	Non Hedges Energy-Related	Fair Value Hedges Interest Rate Swaps	Total Derivatives

	Contracts *	Contracts *			Contracts		
				Millions			
Derivative Contracts							
Current Assets	$ 195	$ 604	$ (586)	$ 213	$ 1	$ 11	$ 225
Noncurrent Assets	162	125	(169)	118	5	0	123
Total Mark-to-Market Derivative Assets	**$ 357**	**$ 729**	**$ (755)**	**$ 331**	**$ 6**	**$ 11**	**$ 348**
Derivative Contracts							
Current Liabilities	$ (57)	$ (662)	$ 518	$ (201)	$ 0	$ 0	$ (201)
Noncurrent Liabilities	(14)	(106)	94	(26)	0	(14)	(40)
Total Mark-to-Market Derivative (Liabilities)	**$ (71)**	**$ (768)**	**$ 612**	**$ (227)**	**$ 0**	**$ (14)**	**$ (241)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 286**	**$ (39)**	**$ (143)**	**$ 104**	**$ 6**	**$ (3)**	**$ 107**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

* **Disclosure Restatement**

Subsequent to the issuance of Power s Form 10-K for the year ended December 31, 2009, Management determined that certain classifying entries were incorrectly included in the above Cash Flow Hedges, Non Hedges, and Netting disclosure table as of December 31, 2009, resulting in offsetting overstatements of both the previously disclosed gross balances of derivative assets and liabilities, as well as the disclosed netting amounts. As a result, such amounts disclosed in the table have been restated from the amounts previously reported to properly reflect the gross amounts of Cash Flow Hedge contracts and Non Hedge contracts and related Netting amounts. These corrections have no impact on Power s Total Net Mark-to-Market Derivative Assets (Liabilities), amounts reflected in Power s balance sheet (the Total Power column above), or PSEG s consolidated Total Derivatives.

(A) Represents the netting of fair value balances with the same counterparty and the application of collateral. As of December 31, 2010 and, 2009, net cash collateral received of $61 million and $143 million, respectively, was netted against the corresponding net derivative contract positions. Of the $61 million as of December 31, 2010, cash collateral of $(132) million and $(3) million were netted against current assets and noncurrent assets, respectively, and cash collateral of $62 million and $12 million were netted against current liabilities and noncurrent liabilities, respectively. 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.

The aggregate fair value of energy-related contracts in a liability position as of December 31, 2010 that contain triggers for additional collateral was $304 million. This potential additional collateral is included in the $828 million discussed in Note 13. Commitments and Contingent Liabilities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2010 and 2009:

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,		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) Years Ended December 31,	
	2010	2009		2010	2009		2010	2009
				Millions				
PSEG (A)								
Energy-Related Contracts	$ 101	$ 636	Operating Revenues	$ 222	$ 644	Operating Revenues	$ 1	$ (22)
Interest Rate Swaps	0	0	Income from Equity Method Investments	0	(1)		0	0
Energy-Related Contracts	1	(45)	Energy Costs	(2)	(67)		0	0
Interest Rate Swaps	0	(4)	Interest Expense	(1)	(3)		0	0
Total PSEG	**$ 102**	**$ 587**		**$ 219**	**$ 573**		**$ 1**	**$ (22)**
PSEG Power								
Energy-Related Contracts	$ 101	$ 636	Operating Revenues	$ 222	$ 644	Operating Revenues	$ 1	$ (22)
Energy-Related Contracts	1	(45)	Energy Costs	(2)	(67)		0	0
Total Power	**$ 102**	**$ 591**		**$ 220**	**$ 577**		**$ 1**	**$ (22)**
PSE&G								
Interest Rate Swaps	$ 0	$ (1)	Interest Expense	$ 0	$ (2)		$ 0	$ 0
Total PSE&G	**$ 0**	**$ (1)**		**$ 0**	**$ (2)**		**$ 0**	**$ 0**
Energy Holdings								
Interest Rate Swaps	$ 0	$ 0	Income from Equity Method Investments	$ 0	$ (1)		$ 0	$ 0
Total Energy Holdings	**$ 0**	**$ 0**		**$ 0**	**$ (1)**		**$ 0**	**$ 0**

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(A) Includes amounts for PSEG Parent.

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, 2009	$ 305	$ 180
Gain Recognized in AOCI (Effective Portion)	102	60
Less: Gain Reclassified into Income (Effective Portion)	(219)	(129)
Balance as of December 31, 2010	**$ 188**	**$ 111**

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 the twelve months ended December 31, 2010 and 2009:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Years Ended December 31,	
		2010	2009
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ (53)	$ 128
Energy-Related Contracts	Energy Costs	(9)	(144)
Derivatives in NDT Funds	Other Income	0	13
Total PSEG and Power		**$ (62)**	**$ (3)**

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 these 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, 2010 and 2009 was to reduce interest expense by approximately $24 million and $1 million, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2010 and 2009:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2010					
Natural Gas	Dth	704	0	424	280
Electricity	MWh	154	0	154	0
Capacity	MW days	1	0	1	0
FTRs	MWh	23	0	23	0
Interest Rate Swaps	US Dollars	1,150	1,150	0	0
As of December 31, 2009					
Natural Gas	Dth	842	0	613	229
Electricity	MWh	190	0	190	0
Capacity	MW days	1	0	1	0
FTRs	MWh	23	0	23	0
Emissions Allowances	Tons	1	0	1	0
Renewable Energy Credits	MWh	1	0	1	0
Interest Rate Swaps	US Dollars	550	550	0	0

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, 2010, 94% 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, 2010. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of 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	$ 1,043	$ 70	$ 1,043	2	$ 644(A)
Non-Investment Grade External Rating	63	0	63	0	0
Investment Grade No External Rating	25	0	25	0	0
Non-Investment Grade No External Rating	10	1	10	0	0
Total	**$ 1,141**	**$ 71**	**$ 1,141**	**2**	**$ 644**

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(A) Includes net exposure of $517 million with PSE&G. The remaining net exposure of $127 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 be no 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, 2010, Power had 197 active counterparties.

Note 17. 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 FTRs, certain full requirements contracts, 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.

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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, 2010 and December 31, 2009, 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, 2010				
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)	$ 222	$ (135)	$ 0	$ 228	$ 129
Interest Rate Swaps(B)	$ 39	$ 0	$ 0	$ 39	$ 0
NDT Funds:(C)					
Equity Securities	$ 735	$ 0	$ 735	$ 0	$ 0
Debt Securities Govt Obligations	$ 303	$ 0	$ 0	$ 303	$ 0
Debt Securities Other	$ 255	$ 0	$ 0	$ 255	$ 0
Other Securities	$ 70	$ 0	$ 0	$ 62	$ 8
Rabbi Trusts Mutual Funds(C)	$ 160	$ 0	$ 18	$ 142	$ 0
Other Long-Term Investments(D)	$ 2	$ 0	$ 2	$ 0	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (125)	$ 74	$ 0	$ (117)	$ (82)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 205	$ (135)	$ 0	$ 228	$ 112
NDT Funds:(C)					
Equity Securities	$ 735	$ 0	$ 735	$ 0	$ 0
Debt Securities Govt Obligations	$ 303	$ 0	$ 0	$ 303	$ 0
Debt Securities Other	$ 255	$ 0	$ 0	$ 255	$ 0
Other Securities	$ 70	$ 0	$ 0	$ 62	$ 8
Rabbi Trusts Mutual Funds(C)	$ 32	$ 0	$ 4	$ 28	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (113)	$ 74	$ 0	$ (117)	$ (70)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 17	$ 0	$ 0	$ 0	$ 17
Rabbi Trusts Mutual Funds(C)	$ 54	$ 0	$ 6	$ 48	$ 0
Liabilities:					
Energy-Related Contracts(A)	$ (12)	$ 0	$ 0	$ 0	$ (12)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	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)	$ 337	$ (223)	$ 0	$ 415	$ 145
Interest Rate Swaps(B)	$ 11	$ 0	$ 0	$ 11	$ 0
NDT Funds:(C)					
Equity Securities	$ 650	$ 0	$ 650	$ 0	$ 0
Debt Securities-Govt Obligations	$ 297	$ 0	$ 0	$ 297	$ 0
Debt Securities-Other	$ 216	$ 0	$ 0	$ 216	$ 0
Other Securities	$ 36	$ 0	$ 0	$ 27	$ 9
Rabbi Trusts Mutual Funds(C)	$ 149	$ 0	$ 14	$ 121	$ 14
Other Long-Term Investments(D)	$ 2	$ 0	$ 2	$ 0	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (227)	$ 80	$ 0	$ (267)	$ (40)
Interest Rate Swaps(B)	$ (14)	$ 0	$ 0	$ (14)	$ 0
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 331	$ (223)	$ 0	$ 415	$ 139
NDT Funds:(C)					
Equity Securities	$ 650	$ 0	$ 650	$ 0	$ 0
Debt Securities-Govt Obligations	$ 297	$ 0	$ 0	$ 297	$ 0
Debt Securities-Other	$ 216	$ 0	$ 0	$ 216	$ 0
Other Securities	$ 36	$ 0	$ 0	$ 27	$ 9
Rabbi Trusts Mutual Funds(C)	$ 30	$ 0	$ 3	$ 24	$ 3
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ (227)	$ 80	$ 0	$ (267)	$ (40)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts(A)	$ 6	$ 0	$ 0	$ 0	$ 6
Rabbi Trusts Mutual Funds(C)	$ 51	$ 0	$ 5	$ 41	$ 5

(A) Level 2 Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average midpoint from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

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Level 3 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. For certain energy-related option contracts where daily settled option prices are not observable, a traditional Black-Scholes valuation methodology is used which incorporates an internally developed volatility curve that is considered a significant unobservable input. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data. We considered the creditworthiness of our counterparties in the valuation of our energy-related contracts and the impacts are immaterial.

(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. Investments in marketable equity securities within the NDT funds are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or in some cases midpoint, bid or ask price (primarily Level 1).

Power s investments in fixed income securities are primarily with investment grade corporate bonds and U.S. Treasury obligations or Federal Agency mortgage-backed securities with a wide range of maturities. Fixed income securities are priced using an evaluated pricing methodology that reflects observable market information such as the most recent exchange price or quoted bid for similar securities. (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 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 U.S. 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.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for twelve months ended December 31, 2010 and 2009 follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis

for the Twelve Months Ended December 31, 2010

Description	Balance as of January 1, 2010	Total Gains or (Losses) Realized/Unrealized: Included in Income(A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities(B)	Purchases, (Sales) and Settlements	Balance as of December 31, 2010
			Millions		
PSEG					
Net Derivative Assets	$ 105	$ (36)	$ (1)	$ (21)	$ 47
NDT Funds	$ 9	$ 0	$ 0	$ (1)	$ 8
Rabbi Trust Funds	$ 14	$ 0	$ 0	$ (14)	$ 0
Power					
Net Derivative Assets	$ 99	$ (36)	$ 0	$ (21)	$ 42
NDT Funds	$ 9	$ 0	$ 0	$ (1)	$ 8
Rabbi Trust Funds	$ 3	$ 0	$ 0	$ (3)	$ 0
PSE&G					
Net Derivative Assets	$ 6	$ 0	$ (1)	$ 0	$ 5
Rabbi Trust Funds	$ 5	$ 0	$ 0	$ (5)	$ 0

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis

for the Twelve Months Ended December 31, 2009

Description	Balance as of January 1, 2009	Total Gains or (Losses) Realized/Unrealized: Included in Income(C)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities(B)	Purchases, (Sales) and Settlements	Balance as of December 31, 2009
			Millions		
PSEG					
Net Derivative Assets (Liabilities)	$ (2)	$ 127	$ 70	$ (90)	$ 105
NDT Funds	$ 41	$ 0	$ 0	$ (32)	$ 9
Rabbi Trust Funds	$ 14	$ 0	$ 0	$ 0	$ 14
Power					
Net Derivative Assets	$ 62	$ 127	$ 0	$ (90)	$ 99
NDT Funds	$ 41	$ 0	$ 0	$ (32)	$ 9
Rabbi Trust Funds	$ 3	$ 0	$ 0	$ 0	$ 3
PSE&G					
	$ (64)	$ 0	$ 70	$ 0	$ 6

Net Derivative Assets (Liabilities)					
Rabbi Trust Funds	$ 5	$ 0	$ 0	$ 0	$ 5

(A) PSEG s and Power s gains and losses are mainly attributable to changes in net derivative assets and liabilities of which $(61) million is included in Operating Income, $2 million is included in OCI, and $23 million is included in Income from Discontinued Operations. Of the $(61) million in Operating Income, $(51) million is unrealized and $(10) million is realized.

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(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/Liability and are expected to be recovered from/returned to 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 $108 million is included in Operating Income, $(18) million is included in OCI and $37 million is included in Income from Discontinued Operations. Of the $108 million in Operating Income, $36 million is unrealized and $72 million is realized.

As of December 31, 2010, PSEG carried $1.7 billion of net assets that are measured at fair value on a recurring basis, of which $55 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 transfers among levels during the year ended December 31, 2010.

As of December 31, 2009, PSEG carried $1.5 billion of net assets that are measured at fair value on a recurring basis, of which $128 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 2009, approximately $15 million of net derivative liabilities were transferred from level 3 to level 2 due to more observable pricing in the Texas market.

Non-recurring Fair Value Measurements:

2010

Due to a significant decline in market prices at December 31, 2010 and June 30, 2010, Power assessed the recoverability of its SO_2 emission allowances not expected to be consumed. As a result of this evaluation, Power recorded pre-tax impairment charges of $3 million and $15 million related to its forecasted excess SO_2 allowances during the quarters ended December 31, 2010 and June 30, 2010, respectively, which are included in Energy Costs in PSEG s and Power s Consolidated Statements of Operations.

As of December 31, 2010, the fair value of remaining excess SO_2 emission allowances of $3 million was determined based on a comparison of quoted market prices where available for each vintage year to the carrying value of the related allowances (Level 2 measurement within the fair value hierarchy). Due to the lack of observable prices beyond certain vintage years, significant internal assumptions were used in the valuation of approximately $1 million of those allowances (Level 3 measurement within the fair value hierarchy).

During the fourth quarter of 2010, Energy Holdings recorded an after-tax impairment charge of $6 million on its investment in GWF Power. The remaining investment was carried as a nonrecurring fair value measurement as of December 31, 2010. This investment was considered a Level 3 within the fair value hierarchy based on the use of unobservable inputs.

During the second quarter of 2010, Energy Holdings executed a new lease, triggering an assessment of the recoverability of existing property located in Michigan. As a result of the evaluation, Energy Holdings recorded a pre-tax impairment of $10 million during the quarter ended June 30, 2010, which is included in Operating Revenues in PSEG s Consolidated Statement of Operations. The fair value of the property was determined using an internal model based on a discounted cash flow analysis (income approach valuation technique) with significant unobservable inputs (Level 3).

2009

During the second quarter of 2009, Energy Holdings sold a 10.1% interest in its investment in GWF Energy and recorded an after-tax impairment charge of $3 million on the entire investment prior to the sale. The remaining investment was carried as a nonrecurring fair value measurement as of June 30, 2009. This investment was 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 was carried as a nonrecurring fair value measurement as of December 31, 2009. The investment was 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 14. Schedule of Consolidated Debt.

Note 18. 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 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, 2010, 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 or cliff vests over three 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, retirement, death or disability.

Performance Units

Under the 2004 LTIP, performance 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

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period. The payout varies from 0% to 200% of the number of performance units granted 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 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 pro-rated for the employee s service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), 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 recognizes compensation expense for performance 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.

For the Years Ended December 31,	**2010**	**2009**	**2008**
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 29	$ 27	$ 21
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 12	$ 11	$ 8

There was $1 million, $3 million and $3 million of excess tax benefits included as a financing cash inflow in the Consolidated Statements of Cash Flow for the years ended December 31, 2010, 2009 and 2008, 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.

Changes in stock options for 2010 are summarized as follows:

	2010	
	Options	**Weighted Average Exercise Price**
Beginning of Year	4,142,050	$ 32.06
Exercised	(136,050)	22.81
Cancelled	(345,366)	33.95
End of Year	**3,660,634**	**$ 32.22**
Exercisable at End of Year	2,254,434	$ 31.43

Options	**Weighted Average Remaining**	**Aggregate Intrinsic Value**

	Years Contractual Term		
Outstanding at December 31, 2010	6.9	$	(1,518,647)
Exercisable at December 31, 2010	6.1	$	852,196

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The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no grants in 2010. The following weighted average assumptions were used for grants in 2009 and 2008:

	2009	2008
Expected Volatility	29.00%	29.30%
Risk-Free Interest Rate	2.84%	1.72%
Expected Life (Years)	6.25	6.25
Weighted Average Dividend Yield	4.00%	4.30%

The expected volatility assumption is based on the historical volatility of daily stock prices. The risk-free rate assumption is based upon U.S. Treasury yields in effect at the time of grant. 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 for the years ended December 31, 2010, 2009 and 2008 is shown below:

	2010	2009	2008
		Millions	
Total Intrinsic Value of Options Exercised	$ 1	$ 4	$ 4
Cash Received from Options Exercised	$ 3	$ 11	$ 5
Tax Benefit Realized from Options Exercised	$ 1	$ 3	$ 3

Approximately one million options vested during the years ended December 31, 2010, 2009 and 2008. The weighted average fair value per share for options vested during the years ended December 31, 2010, 2009 and 2008 was $34.57, $35.07 and $35.40, respectively.

As of December 31, 2010, there was approximately $7 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted average period of 1.09 years.

Restricted Stock Information

Changes in restricted stock for the year ended December 31, 2010 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	236,558	$ 36.03		
Vested	(117,600)	36.29		
Canceled	(1,256)	41.47		
Outstanding at December 31, 2010	**117,702**	**$ 35.71**	**1.3**	**$ 3,744,101**

The weighted average grant date fair value per share was $30.18 for restricted stock awards granted during 2009. There were no restricted stock awards granted in 2010 and 2008.

The total intrinsic value of restricted stock vested during the years ended December 31, 2010 and 2009 was $3 million and $3 million, respectively.

As of December 31, 2010, there was approximately $1 million of unrecognized compensation cost-related to restricted stock, which is expected to be recognized over a weighted average period of 1.11 years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2010 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	650,189	$ 35.69		
Granted	353,440	31.13		
Vested	(165,918)	37.52		
Canceled	(23,350)	36.10		
Outstanding at December 31, 2010	**814,361**	**$ 33.33**	**2.1**	**$ 25,904,823**

The total intrinsic value of restricted stock units vested during the year ended December 31, 2010 was $6 million.

As of December 31, 2010, there was approximately $18 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of 1.30 years. 28,008 dividend equivalents accrued on the restricted stock units during the year.

Performance Units Information

Changes in Performance Units for the year ended December 31, 2010 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2010	719,464	$ 34.70		
Granted	397,885	34.29		
Vested	(206,690)	38.24		
Cancelled	(29,070)	32.12		
Outstanding at December 31, 2010	**881,589**	**$ 33.77**	**2.1**	**$ 28,043,346**

As of December 31, 2010, there was approximately $20 million of unrecognized compensation cost related to the performance units, which is expected to be recognized over a weighted average period of 1.34 years. 37,807 dividend equivalents accrued on the performance share units during the year.

Outside Directors

Beginning in 2007, under the Directors Equity Plan, annually, on May 1, each non-employee member of the Board of Directors 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 plan for each of the years ended December 31, 2010, 2009 and 2008 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, 2010, 2009 and 2008, employees purchased 178,684, 173,350 and 109,921 shares at an average price of $30.32, $29.20 and $38.35 per share, respectively. As of December 31, 2010, 3.6 million shares were available for future issuance under this plan.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 19. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
For the Year Ended December 31, 2010:				
NDT Fund Gains, Interest, Dividend and Other Income	$ 159	$ 0	$ 0	$ 159
Realized Gains from Rabbi Trust	7	11	13	31
Other	4	15	12	31
Total Other Income	**$ 170**	**$ 26**	**$ 25**	**$ 221**
For the Year Ended December 31, 2009:				
NDT Fund Gains, Interest, Dividend and Other Income	$ 227	$ 0	$ 0	$ 227
Other	6	8	5	19
Total Other Income	**$ 233**	**$ 8**	**$ 5**	**$ 246**
For the Year Ended December 31, 2008:				
NDT Fund Gains, Interest, Dividend and Other Income	$ 407	$ 0	$ 0	$ 407
Other	7	12	8	27
Total Other Income	**$ 414**	**$ 12**	**$ 8**	**$ 434**

Other Deductions	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
For the Year Ended December 31, 2010:				
NDT Fund Realized Losses and Expenses	$ 45	$ 0	$ 0	$ 45
Other	8	3	7	18
Total Other Deductions	**$ 53**	**$ 3**	**$ 7**	**$ 63**
For the Year Ended December 31, 2009:				
NDT Fund Realized Losses and Expenses	$ 117	$ 0	$ 0	$ 117
Other	18	3	23	44
Total Other Deductions	**$ 135**	**$ 3**	**$ 23**	**$ 161**
For the Year Ended December 31, 2008:				
NDT Fund Realized Losses and Expenses	$ 302	$ 0	$ 0	$ 302
Other	14	4	16	34

Total Other Deductions	**$ 316**	**$ 4**	**$ 16**	**$ 336**

(A) Other primarily consists of activity at PSEG (parent company), Energy Holdings and Services and intercompany eliminations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 20. 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:

	For the Years Ended December 31,		
	2010	2009	2008
		Millions	
Net Income	$ 1,564	$ 1,592	$ 1,188
Income (loss) from Discontinued Operations, including Gain on Disposal, net of tax	7	(2)	270
Income from Continuing Operations	1,557	1,594	918
Preferred Dividends	(1)	(4)	(4)
Income from Continuing Operations, excluding Preferred Dividends	$ 1,558	$ 1,598	$ 922
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (166)	$ 560	$ 1,372
State	157	257	123
Total Current	(9)	817	1,495
Deferred Expense:			
Federal	992	178	(748)
State	79	44	144
Total Deferred	1,071	222	(604)
Foreign	0	0	0
Investment Tax Credit	(3)	3	(3)
Total Income Taxes	**$ 1,059**	**$ 1,042**	**$ 888**
Pre-Tax Income	$ 2,617	$ 2,640	$ 1,810
Tax Computed at Statutory Rate @ 35%	$ 916	$ 924	$ 634
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	154	201	169
Uncertain Tax Positions	30	(73)	135
Manufacturing Deduction	(24)	(7)	(22)
Nuclear Decomissioning Trust	10	7	(10)
Plant Related Items	(3)	3	0
Tax Credits	(2)	(3)	(3)
Other	(22)	(10)	(15)

Sub-Total	143	118	254
Total Income Tax Provision	**$ 1,059**	**$ 1,042**	**$ 888**
Effective Income Tax Rate	40.5%	39.5%	49.1%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSEG:

	As of December 31, 2010	As of December 31, 2009
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 43	$ 0
Non-Current:		
Unrecovered Investment Tax Credit	18	14
Accumulated Other Comprehensive Income (Loss)	79	28
Cumulative Effect of a Change in Accounting Principle	11	11
New Jersey Corporate Business Tax	17	52
OPEB	197	269
Cost of Removal	51	51
Contractual Liabilities and Environmental Costs	35	35
MTC	47	17
Related to Uncertain Tax Positions	73	507
Other	58	14
Total Non-Current	586	998
Total Assets	$ 629	$ 998
Liabilities:		
Current (net)	$ 0	$ 7
Non-Current:		
Plant-Related Items	3,169	2,133
Nuclear Decommissioning	171	113
Securitization	686	771
Leasing Activities	839	1,246
Partnership Activity	18	29
Conservation Costs	62	26
Energy Clause Recoveries	76	72
Pension Costs	189	124
AROs	287	299
Taxes Recoverable Through Future Rate (net)	158	159
Other	18	19
Total Non-Current Liabilities	5,673	4,991
Total Liabilities	$ 5,673	$ 4,998
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	$ 43	$ 0

Net Current Deferred Income Tax Liability	$ 0	$ 7
Net Non-Current Deferred Income Tax Liability	$ 5,087	$ 3,993
Investment Tax Credit (ITC)	42	52
Net Total Non-Current Deferred Income Taxes and ITC	**$ 5,129**	**$ 4,045**

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:

	For the Years Ended December 31,		
	2010	2009	2008
		Millions	
Net Income	$ 1,143	$ 1,189	$ 1,115
Income (Loss) from Discontinued Operations, net of tax	7	(2)	65
Income from Continuing Operations	$ 1,136	$ 1,191	$ 1,050
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 12	$ 416	$ 429
State	127	144	130
Total Current	139	560	559
Deferred Expense:			
Federal	598	177	86
State	41	30	16
Total Deferred	639	207	102
Total Income Taxes	**$ 778**	**$ 767**	**$ 661**
Pre-Tax Income	$ 1,914	$ 1,958	$ 1,711
Tax Computed at Statutory Rate @ 35%	$ 670	$ 685	$ 599
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	109	113	95
Manufacturing Deduction	(24)	(7)	(22)
Nuclear Decommissioning Trust	10	7	(10)
Uncertain Tax Positions	10	(26)	5
Other	3	(5)	(6)
Sub-Total	108	82	62
Total Income Tax Provision	**$ 778**	**$ 767**	**$ 661**
Effective Income Tax Rate	40.6%	39.2%	38.6%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

	As of December 31,	
	2010	**2009**
Deferred Income Taxes	Millions	
Assets:		
Non-Current:		
Cumulative Effect of a Change in Accounting Principle	$ 11	$ 11
New Jersey Corporate Business Tax	73	69
Pension Costs	12	48
Accumulated Other Comprehensive Income (Loss)	40	0
Cost of Removal	51	51
Contractual Liabilities & Environmental Costs	35	35
Other	38	0
Total Non-Current	260	214
Total Assets	$ 260	$ 214
Liabilities:		
Current (net)	$ 64	$ 0
Non-Current:		
Plant-Related Items	927	349
OCI	0	10
Nuclear Decommissioning	171	113
AROs	287	299
Related to Uncertain Tax Positions	16	37
Other	0	10
Total Non-Current Liabilities	1,401	818
Total Liabilities	$ 1,465	$ 818
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Liabilities	$ 64	$ 0
Net Non-Current Deferred Income Tax Liability	$ 1,141	$ 604
Investment Tax Credit (ITC)	5	5
Net Total Non-Current Deferred Income Taxes and ITC	**$ 1,146**	**$ 609**

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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:

	For the Years Ended December 31,		
	2010	2009	2008
	Millions		
Net Income	$ 358	$ 321	$ 360
Preferred Dividends	(1)	(4)	(4)
Income from Continuing Operations, excluding Preferred Dividends	$ 359	$ 325	$ 364
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (211)	$ 7	$ 74
State	(1)	22	38
Total Current	(212)	29	112
Deferred Expense:			
Federal	384	158	92
State	63	38	26
Total Deferred	447	196	118
Investment Tax Credit	(3)	1	(2)
Total Income Taxes	**$ 232**	**$ 226**	**$ 228**
Pre-Tax Income	$ 591	$ 551	$ 592
Tax Computed at Statutory Rate @ 35%	$ 207	$ 193	$ 207
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	40	39	42
Uncertain Tax Positions	(1)	(3)	(18)
Plant-Related Items	(3)	3	0
Tax Credits	(2)	(3)	(3)
Other	(9)	(3)	0
Sub-Total	25	33	21
Total Income Tax Provision	**$ 232**	**$ 226**	**$ 228**
Effective Income Tax Rate	39.2%	41.0%	38.5%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSE&G:

	As of December 31,	
	2010	**2009**
Deferred Income Taxes	Millions	
Assets:		
Non-Current:		
Unrecovered ITC	$ 12	$ 14
New Jersey Corporate Business Tax	0	57
OPEB	189	263
Related to Uncertain Tax Positions	24	0
MTC	47	17
Other	5	26
Total Non-Current	277	377
Total Assets	$ 277	$ 377
Liabilities:		
Current (net)	$ 19	$ 7
Non-Current:		
Plant-Related Items	2,216	$ 1,793
OCI	0	3
Securitization	686	771
Conservation Costs	62	26
Energy Clause Recoveries	76	72
Pension Costs	172	141
Related to Uncertain Tax Positions	0	23
Taxes Recoverable Through Future Rate (net)	158	159
Total Non-Current Liabilities	3,370	2,988
Total Liabilities	3,389	$ 2,995
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Liability	$ 19	$ 7
Net Non-Current Deferred Income Tax Liability	$ 3,093	$ 2,611
Investment Tax Credit (ITC)	34	40
Net Total Non-Current Deferred Income Taxes and ITC	**$ 3,127**	**$ 2,651**

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 or refunded to PSE&G s customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 6. Regulatory Assets and Liabilities.

The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 include various health care-related provisions which will go into effect over the next several years. One of the provisions eliminates the tax deductibility of retiree health care costs, to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D

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coverage. Although this change does not take effect immediately, the accounting impact was required to be recognized when the legislation was signed. As a result, in the first quarter of 2010, PSEG recorded noncash after tax charges of $9 million for income tax expense to establish the related deferred tax liabilities, primarily related to Power. There was no immediate impact on PSE&G s income tax expense or effective tax rate since the related amount of $78 million was deferred as a Regulatory Asset to be collected and amortized over future periods.

Two other tax provisions were enacted during 2010 that will have significant impact on PSEG s cash position. The Small Business Jobs Act of 2010, enacted September 27, 2010, extended the tax deduction for 50% bonus depreciation through 2010 for qualified property. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, enacted December 17, 2010, included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 will be eligible for 50% bonus depreciation for tax purposes. These provisions will generate cash for PSEG through tax benefits related to the accelerated depreciation most of which is anticipated to be realized in 2011. These tax benefits would have otherwise been received over an estimated average 20 year period.

PSEG and PSE&G have accrued $84 million and $52 million, respectively, of Investment Tax Credits (ITC) associated with alternative energy projects. Because the law provides an option to claim either a grant or the ITC, the ITC has been accounted for as a reduction of the book basis of the related assets as opposed to being recorded in tax expense.

PSEG recorded the following amounts related to its unrecognized tax benefits, which was primarily comprised of amounts recorded for Power, PSE&G and Energy Holdings:

2010	**PSEG**	**Power**	**PSE&G**	**Energy Holdings**
		Millions		
Total Amount of Unrecognized Tax Benefits at January 1, 2010	$ 836	$ (42)	$ 35	$ 820
Increases as a Result of Positions Taken in a Prior Period	290	111	79	90
Decreases as a Result of Positions Taken in a Prior Period	(450)	(29)	(38)	(383)
Increases as a Result of Positions Taken during the Current Period	82	63	6	12
Decreases as a Result of Positions Taken during the Current Period	(2)	(2)	0	0
Decreases as a Result of Settlements with Taxing Authorities	0	0	0	0
Decreases due to Lapses of Applicable Statute of Limitations	0	0	0	0
Total Amount of Unrecognized Tax Benefits at December 31, 2010	$ 756	$ 101	$ 82	$ 539
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(332)	(67)	(38)	(204)
Regulatory Asset Unrecognized Tax Benefits	(16)	0	(16)	0
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 408**	**$ 34**	**$ 28**	**$ 335**

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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)	0
Decreases as a Result of Settlements with Taxing Authorities	(5)	(5)	0	0
Decreases due to Lapses of Applicable Statute of Limitations	(15)	(12)	0	(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)	0	(55)	0
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)	0	(1)	(1)
Decreases as a Result of Settlements with Taxing Authorities	(20)	0	0	(20)
Decreases due to Lapses of Applicable Statute of Limitations	0	0	0	0
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)	0	(39)	0
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 347**	**$ 20**	**$ 6**	**$ 314**

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 13. Commitments and Contingent Liabilities). The $320 million of deposits are fully refundable and are recorded to the Current Accrued Taxes on PSEG s Consolidated Balance Sheets, but are not reflected in the amounts shown above.

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PSEG and its subsidiaries include all accrued interest and penalties related to uncertain tax positions required to be recorded, as income tax expense. Interest and penalties on uncertain tax positions were as follows:

	Interest and Penalties on Uncertain Tax Positions Years Ended December 31,		
	2010	2009	2008
		Millions	
Power	$ (17)	$ (2)	$ 10
PSE&G	(20)	(22)	(22)
Energy Holdings	407	370	354
Other	9	8	7
Total	**$ 379**	**$ 354**	**$ 349**

It is reasonably possible that total unrecognized tax benefits will decrease within the next 12 months due to either agreements with various taxing authorities upon audit or the expiration of the Statute of Limitations. These potential decreases are as follows:

Possible Decrease in Total Unrecognized Tax Benefits Including Interest	Over the next 12 Months
	Millions
PSEG	$ 575
Power	$ 48
PSE&G	$ 56

As a result of a change in accounting method for the capitalization of indirect costs, PSEG reduced the net amount of its uncertain tax positions (including interest) by $96 million, approximately $42 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 uncertain tax positions. These amounts are not included in the table above.

It is reasonably possible that unrecognized tax benefits associated with the leasing tax issue discussed in Note 13. 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 $190 million or decrease by as much as $300 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	2004-2009	2004-2009	2004-2009
New Jersey	2006-2009	N/A	2006-2009
Pennsylvania	2004-2009	N/A	2006-2009
Connecticut	2005-2009	N/A	N/A
Texas	2007-2009	N/A	N/A
California	2003-2009	N/A	N/A
New York	2004-2009	2004-2009	N/A

Note 21. 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 our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	For the Years Ended December 31,					
	2010		2009		2008	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Continuing Operations	$ 1,557	$ 1,557	$ 1,594	$ 1,594	$ 918	$ 918
Discontinued Operations	7	7	(2)	(2)	270	270
Net Income	**$ 1,564**	**$ 1,564**	**$ 1,592**	**$ 1,592**	**$ 1,188**	**$ 1,188**
EPS Denominator:						
(Thousands)						
Weighted Average Common Shares Outstanding	505,985	505,985	505,986	505,986	507,693	507,693
Effect of Stock Options	0	152	0	183	0	341
Effect of Stock Performance Share Units	0	749	0	786	0	322
Effect of Restricted Stock	0	0	0	0	0	0
Effect of Restricted Stock Units	0	159	0	109	0	71
Total Shares	**505,985**	**507,045**	**505,986**	**507,064**	**507,693**	**508,427**
EPS:						
Continuing Operations	$ 3.08	$ 3.07	$ 3.15	$ 3.14	$ 1.81	$ 1.81
Discontinued Operations	0.01	0.01	0.00	0.00	0.53	0.53

Net Income	**$ 3.09**	**$ 3.08**	**$ 3.15**	**$ 3.14**	**$ 2.34**	**$ 2.34**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

There were approximately 1.9 million and 1.6 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2010 and 2009, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2010, 2009 or 2008.

Dividends

	For the Years Ended December 31,		
Dividend Payments on Common Stock	**2010**	**2009**	**2008**
Per Share	$ 1.37	$ 1.33	$ 1.29
in Millions	$ 693	$ 673	$ 655

On February 15, 2011, PSEG s Board of Directors approved a $0.3425 per share common stock dividend for the first quarter of 2011.

Note 22. 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.

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, FTRs, 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 domestic leveraged leases. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case 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 23. Related-Party Transactions. The net losses primarily relate to financing and certain administrative and general costs.

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2010:					
Operating Revenues	$ 6,558	$ 7,869	$ 137	$ (2,771)	$ 11,793
Depreciation and Amortization	175	750	14	16	955
Operating Income (Loss)	1,963	886	81	7	2,937
Income from Equity Method Investments	0	0	4	0	4
Interest Income	3	7	2	8	20
Interest Expense	157	318	11	(14)	472
Income (Loss) before Income Taxes	1,914	591	86	25	2,616
Income Tax Expense (Benefit)	778	232	37	12	1,059
Income (Loss) from Continuing Operations	1,136	359	49	13	1,557
Income from Discontinued Operations, net of tax	7	0	0	0	7
Net Income (Loss)	1,143	359	49	13	1,564
Segment Earnings (Loss)	1,143	358	49	14	1,564
Gross Additions to Long-Lived Assets	$ 825	$ 1,257	$ 63	$ 15	$ 2,160
As of December 31, 2010:					
Total Assets	$ 11,452	$ 16,873	$ 2,234	$ (650)	$ 29,909
Investments in Equity Method Subsidiaries	$ 25	$ 0	$ 105	$ 0	$ 130

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2009:					
Operating Revenues	$ 6,772	$ 8,243	$ 221	$ (3,201)	$ 12,035
Depreciation and Amortization	184	608	11	16	819
Operating Income (Loss)	2,081	858	163	14	3,116
Income from Equity Method Investments	0	0	17	0	17
Interest Income	6	2	5	(6)	7
Interest Expense	161	312	37	11	521
Income (Loss) before Income Taxes	1,958	551	117	10	2,636
Income Tax Expense (Benefit)	767	226	45	4	1,042
Income (Loss) from Continuing Operations	1,191	325	72	6	1,594
Loss from Discontinued Operations, net of tax	(2)	0	0	0	(2)
Net Income (Loss)	1,189	325	72	6	1,592
Segment Earnings (Loss)	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	$ 16,481	$ 2,605	$ (741)	$ 28,678
Investments in Equity Method Subsidiaries	$ 36	$ 0	$ 176	$ 0	$ 212

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
For the Year Ended December 31, 2008:					
Operating Revenues	$ 7,770	$ 9,038	$ (368)	$ (3,831)	$ 12,609
Depreciation and Amortization	164	583	12	16	775
Operating Income (Loss)	1,996	909	(437)	16	2,484
Income from Equity Method Investments	0	0	10	0	10
Interest Income	7	5	21	(16)	17
Interest Expense	164	325	57	20	566
Income (Loss) before Income Taxes	1,711	592	(459)	(38)	1,806
Income Tax Expense (Benefit)	661	228	9	(10)	888
Income (Loss) from Continuing Operations	1,050	364	(468)	(28)	918
Income from Discontinued Operations, net of tax (including Gain on Disposal)	65	0	205	0	270
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

Note 23. 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 financial statements for Power include transactions with related parties presented as follows:

	Years Ended December 31,		
Related Party Transactions	**2010**	**2009**	**2008**
		Millions	
Revenue from Affiliates:			
Billings to PSE&G through BGSS(A)	$ 1,591	$ 1,838	$ 2,316
Billings to PSE&G through BGS(A)	1,139	1,322	1,453
Total Revenue from Affiliates	**$ 2,730**	**$ 3,160**	**$ 3,769**
Expense Billings from Affiliates:			
Administrative Billings from Services(B)	$ (145)	$ (153)	$ (166)
Total Expense Billings from Affiliates	**$ (145)**	**$ (153)**	**$ (166)**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Related Party Transactions	Years Ended December 31, 2010	2009
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts(A)	$ 372	$ 404
Receivables from PSE&G Related to Gas Supply Hedges for BGSS(A)	58	120
Payable to Services(B)	(26)	(27)
Tax Sharing Receivable from (Payable to) PSEG(C)	380	(28)
Current Unrecognized Tax Receivable from PSEG(C)	1	3
Payable to PSEG	(3)	(13)
Accounts Receivable Affiliated Companies, net	**$ 782**	**$ 459**
Short-Term Loan to (from) Affiliate (demand Note to (from) PSEG)(D)	**$ 398**	**$ (194)**
Working Capital Advances to Services(E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable(C)	**$ 16**	**$ 39**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2010	2009	2008
		Millions	
Expense Billings from Affiliates:			
Billings from Power through BGSS(A)	$ (1,591)	$ (1,838)	$ (2,316)
Billings from Power through BGS(A)	(1,139)	(1,322)	(1,453)
Administrative Billings from Services(B)	$ (206)	$ (240)	$ (264)
Total Expense Billings from Affiliates	**$ (2,936)**	**$ (3,400)**	**$ (4,033)**

Related Party Transactions	Years Ended December 31, 2010	2009
	Millions	
Payable to Power through BGS and BGSS Contracts(A)	$ (372)	$ (404)
Payable to Power Related to Gas Supply Hedges for BGSS(A)	(58)	(120)
Payable to Power from SREC Liability(F)	(7)	(7)
Payable to Services(B)	(48)	(42)
Tax Sharing Receivable from (Payable to) PSEG(C)	321	13
Current Unrecognized Tax Receivable from PSEG(C)	73	61
Receivable from PSEG	6	3
Accounts Payable Affiliated Companies, net	**$ (85)**	**$ (496)**
Working Capital Advances to Services(E)	**$ 33**	**$ 33**

Long-Term Accrued Taxes Payable(C)	**$ (74)**	**$ (96)**

(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, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(B) Services provides and bills administrative services to Power and PSE&G at cost. 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.

(C) PSEG files a consolidated Federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

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) Power s short-term loans with PSEG are for working capital and other 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 January 2008 the BPU issued a decision that certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (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. The N.J. Division of Rate Counsel (Rate Counsel) filed an appeal of the BPU decision and the Appellate Division of the Superior Court affirmed the BPU order in November 2009. However, the N.J. Supreme Court granted the Rate Counsel s Petition for Certification and the matter is pending before the Supreme Court. The Supreme Court held oral arguments on October 14, 2010 and a decision is expected within the next few months. PSE&G has estimated and accrued a total liability for the excess SREC cost of $17 million and $15 million as of December 31, 2010 and 2009, respectively, 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, 2010 and 2009.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 24. 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,	
	2010	2009	2010	2009	2010	2009	2010	2009
PSEG Consolidated:	Millions							
Operating Revenues	$ 3,573	$ 3,829	$ 2,361	$ 2,497	$ 3,114	$ 2,897	$ 2,745	$ 2,812
Operating Income	$ 946	$ 925	$ 431	$ 653	$ 971	$ 868	$ 589	$ 670
Income from Continuing Operations	$ 498	$ 447	$ 222	$ 320	$ 547	$ 453	$ 290	$ 374
Income (Loss) from Discontinued Operations, net of tax	$ (7)	$ (3)	$ 2	$ (9)	$ 20	$ 35	$ (8)	$ (25)
Net Income	$ 491	$ 444	$ 224	$ 311	$ 567	$ 488	$ 282	$ 349
Earnings Per Share:								
Basic:								
Income from Continuing Operations	$ 0.99	$ 0.89	$ 0.44	$ 0.63	$ 1.08	$ 0.89	$ 0.57	$ 0.75
Net Income	$ 0.97	$ 0.88	$ 0.44	$ 0.61	$ 1.12	$ 0.96	$ 0.56	$ 0.70
Diluted:								
Income from Continuing Operations	$ 0.99	$ 0.89	$ 0.44	$ 0.63	$ 1.08	$ 0.89	$ 0.57	$ 0.74
Net Income	$ 0.97	$ 0.88	$ 0.44	$ 0.61	$ 1.12	$ 0.96	$ 0.56	$ 0.69
Weighted Average Common Shares Outstanding:								
Basic	506	506	506	506	506	506	506	506
Diluted	507	507	507	507	507	507	507	507

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2010	2009	2010	2009	2010	2009	2010	2009
Power:	Millions							
Operating Revenues	$ 2,196	$ 2,373	$ 1,264	$ 1,300	$ 1,523	$ 1,421	$ 1,575	$ 1,678
Operating Income	$ 651	$ 606	$ 348	$ 418	$ 607	$ 596	$ 357	$ 461
Income from Continuing Operations	$ 371	$ 317	$ 202	$ 256	$ 364	$ 347	$ 199	$ 271
Income (Loss) from Discontinued Operations, net of tax	$ (7)	$ (3)	$ 2	$ (9)	$ 20	$ 35	$ (8)	$ (25)
Net Income	$ 364	$ 314	$ 204	$ 247	$ 384	$ 382	$ 191	$ 246

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2010	2009	2010	2009	2010	2009	2010	2009
PSE&G:	Millions							
Operating Revenues	$ 2,444	$ 2,735	$ 1,536	$ 1,643	$ 2,007	$ 1,943	$ 1,882	$ 1,922
Operating Income	$ 271	$ 288	$ 71	$ 150	$ 325	$ 226	$ 219	$ 194
Income from Continuing Operations	$ 118	$ 124	$ 3	$ 44	$ 155	$ 88	$ 83	$ 69
Net Income	$ 118	$ 124	$ 3	$ 44	$ 155	$ 88	$ 83	$ 69
Earnings Available to PSEG	$ 117	$ 123	$ 3	$ 43	$ 155	$ 87	$ 83	$ 68

Note 25. 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 financial information for the guarantor subsidiaries as well as Power s non-guarantor subsidiaries as of December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2010:					
Operating Revenues	$ 0	$ 7,746	$ 125	$ (1,313)	$ 6,558
Operating Expenses	9	5,760	139	(1,313)	4,595
Operating Income (Loss)	(9)	1,986	(14)	0	1,963
Equity Earnings (Losses) of Subsidiaries	1,182	(15)	0	(1,167)	0
Other Income	45	170	0	(45)	170
Other Deductions	(4)	(49)	0	0	(53)
Other-Than-Temporary Impairments	0	(9)	0	0	(9)
Interest Expense	(113)	(67)	(22)	45	(157)
Income Tax Benefit (Expense)	42	(834)	14	0	(778)
Income (Loss) on Discontinued Operations, net of tax	0	0	7	0	7
Net Income (Loss)	**$ 1,143**	**$ 1,182**	**$ (15)**	**$ (1,167)**	**$ 1,143**
As of December 31, 2010:					
Current Assets	$ 3,988	$ 6,807	$ 1,117	$ (8,468)	$ 3,444
Property, Plant and Equipment, net	55	5,385	902	0	6,342
Investment in Subsidiaries	4,794	1,079	0	(5,873)	0
Noncurrent Assets	170	1,549	41	(94)	1,666
Total Assets	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**
Current Liabilities	$ 751	$ 8,519	$ 849	$ (8,468)	$ 1,651
Noncurrent Liabilities	423	1,510	129	(93)	1,969
Long-Term Debt	2,805	0	0	0	2,805
Member s Equity	5,028	4,791	1,082	(5,874)	5,027
Total Liabilities and Member s Equity	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**
For the Year Ended December 31, 2010:					
Net Cash Provided By (Used In) Operating Activities	$ 467	$ 2,249	$ 28	$ (1,178)	$ 1,566
Net Cash Provided By (Used In) Investing Activities	$ (252)	$ (1,567)	$ (34)	$ 648	$ (1,205)
Net Cash Provided By (Used In) Financing Activities	$ (216)	$ (687)	$ (40)	$ 529	$ (414)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2009:					
Operating Revenues	$ 0	$ 7,932	$ 122	$ (1,282)	$ 6,772
Operating Expenses	4	5,846	125	(1,284)	4,691
Operating Income (Loss)	(4)	2,086	(3)	2	2,081
Equity Earnings (Losses) of Subsidiaries	1,208	(20)	0	(1,188)	0
Other Income	57	256	1	(81)	233
Other Deductions	(14)	(120)	0	(1)	(135)
Other-Than-Temporary Impairments	0	(60)	0	0	(60)
Interest Expense	(145)	(73)	(23)	80	(161)
Income Tax Benefit (Expense)	87	(861)	7	0	(767)
Income (Loss) on Discontinued Operations, net of tax	0	0	(2)	0	(2)
Net Income (Loss)	**$ 1,189**	**$ 1,208**	**$ (20)**	**$ (1,188)**	**$ 1,189**
As of December 31, 2009:					
Current Assets	$ 3,039	$ 5,614	$ 1,114	$ (6,871)	$ 2,896
Property, Plant and Equipment, net	61	4,872	898	0	5,831
Investment in Subsidiaries	4,865	1,093	0	(5,958)	0
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	$ 853	$ (6,869)	$ 1,258
Noncurrent Liabilities	522	1,002	115	(152)	1,487
Long-Term Debt	3,121	0	0	0	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)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
For the Year Ended December 31, 2008:					
Operating Revenues	$ 0	$ 8,887	$ 126	$ (1,243)	$ 7,770
Operating Expenses	0	6,890	126	(1,242)	5,774
Operating Income (Loss)	0	1,997	0	(1)	1,996
Equity Earnings (Losses) of Subsidiaries	1,120	24	0	(1,144)	0
Other Income	162	501	0	(249)	414
Other Deductions	(13)	(302)	0	(1)	(316)
Other-Than-Temporary Impairments	0	(219)	0	0	(219)
Interest Expense	(209)	(147)	(59)	251	(164)
Income Tax Benefit (Expense)	55	(734)	18	0	(661)
Income (Loss) on Discontinued Operations, net of tax	0	0	65	0	65
Net Income (Loss)	**$ 1,115**	**$ 1,120**	**$ 24**	**$ (1,144)**	**$ 1,115**
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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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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, 2010, 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 193, 194 and 195, 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 196. Management has concluded that internal control over financial reporting is effective as of December 31, 2010.

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 2010 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, 2010 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, 2010.

PSEG s external auditors, Deloitte & Touche LLP, have audited PSEG s financial statements for the year ended December 31, 2010 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, 2011

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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, 2010 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, 2010.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer

February 25, 2011

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, 2010 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, 2010.

/s/ Ralph Izzo
Chief Executive Officer

/s/ Caroline Dorsa
Chief Financial Officer

February 25, 2011

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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, 2010, 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 PSEG. 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, 2010, 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(B)(a) as of and for the year ended December 31, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2011

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

Name	Age as of December 31, 2010	Office	Effective Date First Elected to Present Position
Ralph Izzo	53	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	51	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

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Name	Age as of December 31, 2010	Office	Effective Date First Elected to Present Position
William Levis	54	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
Ralph LaRossa	47	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Vice President Electric Delivery (PSE&G)	August 2003 to October 2006
Derek M. DiRisio	46	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
		Assistant Controller Enterprise (Services)	July 2004 to January 2007
Randall E. Mehrberg	55	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.	66	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

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Power and PSE&G

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

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 2011 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 10, 2011 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 2010, 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 2011 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 10, 2011 and such information set forth under such heading is incorporated herein by this reference thereto.

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Section 16 Beneficial Ownership Reporting Compliance

During 2010, none of our directors or executive officers was late in filing a Form 3, 4 or 5 in accordance with the requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, with regard to transactions involving our Common Stock, with the exception of Derek M. DiRisio, Vice President and Controller (who is not one of our NEOs). Mr. DiRisio filed two late reports on Form 4 with respect to two transactions. Both involved the sale of shares of our Common Stock, one of which was our mandatory income tax withholding of shares earned by Mr. DiRisio upon the vesting and payment to him of performance units awarded under the LTIP.

Power and PSE&G

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

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 2011 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2011, 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 2011 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2011 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 2010 and 2009 in PSEG s definitive Proxy Statement for the 2011 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2011. 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, 2010 and 2009 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholders Equity for the three years ended December 31, 2010 on pages 90, 91, 89, 92 and 93, respectively.

b. PSEG Power LLC s Consolidated Balance Sheets as of December 31, 2010 and 2009 and the related Consolidated Statements of Operations, Cash Flows and Capitalization and Member s Equity for the three years ended December 31, 2010 on pages 95, 96, 94, 97 and 98, respectively.

c. Public Service Electric and Gas Company s Consolidated Balance Sheets as of December 31, 2010 and 2009 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholders Equity for the three years ended December 31, 2010 on pages 100, 101, 99, 102 and 103, 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, 2010 (page 209).

b. Power s Financial Statement Schedules:
Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2010 (page 210).

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, 2010 (page 210).

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 (U.S. 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(6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees(7)

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10a(3)	Employment Agreement with William Levis dated December 8, 2006[8]
10a(4)	2007 Equity Compensation Plan for Outside Directors[9]
10a(5)	Employee Stock Purchase Plan[10]
10a(6)	Deferred Compensation Plan for Directors[11]
10a(7)	Deferred Compensation Plan for Certain Employees[12]
10a(8)	1989 Long-Term Incentive Plan, as amended[13]
10a(9)	2001 Long-Term Incentive Plan[14]
10a(10)	Senior Management Incentive Compensation Plan[15]
10a(11)	Amended and Restated Key Executive Severance Plan[16]
10a(12)	Severance Agreement with Ralph Izzo dated December 16, 2008[17]
10a(13)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009[18]
10a(14)	Employment Agreement with Randall Mehrberg dated June 30, 2008[19]
10a(15)	Stock Plan for Outside Directors, as amended[20]
10a(16)	Compensation Plan for Outside Directors[21]
10a(17)	2004 Long-Term Incentive Plan[22]
10a(18)	Form of Advancement of Expenses Agreement with Outside Directors[23]
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
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. 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(24)
3b	PSEG Power LLC Limited Liability Company Agreement(25)
3c	Trust Agreement for PSEG Power Capital Trust I(26)
3d	Trust Agreement for PSEG Power Capital Trust II(27)
3e	Trust Agreement for PSEG Power Capital Trust III(28)
3f	Trust Agreement for PSEG Power Capital Trust IV(29)
3g	Trust Agreement for PSEG Power Capital Trust V(30)
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(31)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(32)
10a(1)	Supplemental Executive Retirement Income Plan(6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees(7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(8)
10a(4)	Employee Stock Purchase Plan(10)
10a(5)	Deferred Compensation Plan for Certain Employees(12)
10a(6)	1989 Long-Term Incentive Plan, as amended(13)
10a(7)	2001 Long-Term Incentive Plan(14)
10a(8)	Senior Management Incentive Compensation Plan(15)
10a(9)	Amended and Restated Key Executive Severance Plan(16)
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008(17)
10a(11)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009(18)
10a(12)	2004 Long-Term Incentive Plan(22)
11	Inapplicable
12a	Computation of Ratio of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23a	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code

c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G[33]
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[34]
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[35]
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[36]
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[37]
3b(1)	By-Laws of PSE&G as in effect April 17, 2007[38]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[39], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	April 1, 1927[40]
4a(3)	June 1, 1937[41]
4a(4)	July 1, 1937[42]
4a(5)	December 19, 1939[43]
4a(6)	March 1, 1942[44]
4a(7)	June 1, 1991 (No. 1)[45]
4a(8)	July 1, 1993[46]
4a(9)	September 1, 1993[47]
4a(10)	February 1, 1994[48]
4a(11)	March 1, 1994 (No. 2)[49]
4a(12)	May 1, 1994[50]
4a(13)	October 1, 1994 (No. 2)[51]
4a(14)	January 1, 1996 (No. 1)[52]
4a(15)	January 1, 1996 (No. 2)[53]
4a(16)	May 1, 1998[54]
4a(17)	September 1, 2002[55]
4a(18)	August 1, 2003[56]
4a(19)	December 1, 2003 (No. 1)[57]
4a(20)	December 1, 2003 (No. 2)[58]
4a(21)	December 1, 2003 (No. 3)[59]
4a(22)	December 1, 2003 (No. 4)[60]

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4a(23)	June 1, 2004[61]
4a(24)	August 1, 2004 (No. 1)[62]
4a(25)	August 1, 2004 (No. 2)[63]
4a(26)	August 1, 2004 (No. 3)[64]
4a(27)	August 1, 2004 (No. 4)[65]
4a(28)	April 1, 2007[66]
4a(29)	November 1, 2008[67]
4a(30)	November 1, 2009[68]
4a(31)	October 1, 2010[69]
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[70]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[71]
10a(1)	Supplemental Executive Retirement Income Plan[6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees[7]
10a(3)	2007 Equity Compensation Plan for Outside Directors[9]
10a(4)	Employee Stock Purchase Plan[10]
10a(5)	Deferred Compensation Plan for Directors[11]
10a(6)	Deferred Compensation Plan for Certain Employees[12]
10a(7)	1989 Long-Term Incentive Plan, as amended[13]
10a(8)	2001 Long-Term Incentive Plan[14]
10a(9)	Senior Management Incentive Compensation Plan[15]
10a(10)	Amended and Restated Key Executive Severance Plan[16]
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008[17]
10a(12)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009[18]
10a(13)	Stock Plan for Outside Directors, as amended[20]
10a(14)	Compensation Plan for Outside Directors[21]
10a(15)	2004 Long-Term Incentive Plan[22]
10a(16)	Form of Advancement of Expenses Agreement with Outside Directors[72]
11	Inapplicable
12b	Computation of Ratios of Earnings to Fixed Charges
12c	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23b	Consent of Independent Registered Public Accounting Firm
24	Inapplicable

31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(2) Filed as Exhibit 3.1 with Current Report on Form 8-K, File No. 001-09120 on November 18, 2009 and incorporated herein by this reference.

(3) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(4) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.

(6) Filed as Exhibit 10a(1) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-09120 on February 25, 2010 and incorporated herein by reference.

(7) Filed as Exhibit 10a(3) with Annual Report on Form 10-K, for the year ended December 31, 2008, File No. 001-09120 on February 26, 2009 and incorporated herein by this reference.

(8) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.

(9) Filed as Exhibit 10a(5) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 001-00973, and incorporated herein by reference.

(10) Filed with Registration Statement on Form S-8, File No. 333-106330 filed on June 20, 2003 and incorporated herein by this reference.

(11) Filed as Exhibit 10a(2) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.

(12) Filed as Exhibit 10a(8) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.

(13)

Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.

(14) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.

(15) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.

(16) Filed as Exhibit 10a(14) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.

(17) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973 on December 22, 2008 and incorporated herein by this reference.

(18) Filed as Exhibit 10a(14) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-09120 on February 25, 2010 and incorporated herein by reference.

(19) Filed as Exhibit 10 with Quarterly Report on Form 10-Q, File No. 001-00973 on May 6, 2009 and incorporated herein by reference.

(20) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.

(21) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.

(22) Filed as Exhibit 10a(21) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-09120, on February 25, 2004 and incorporated herein by this reference.

(23) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120 on February 19, 2009 and incorporated herein by reference.

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(24) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.

(25) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.

(26) Filed as Exhibit 3.6 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(27) Filed as Exhibit 3.7 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(28) Filed as Exhibit 3.8 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(29) Filed as Exhibit 3.9 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(30) Filed as Exhibit 3.10 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(31) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.

(32) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.

(33) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.

(34) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.

(35) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(36) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(37) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(38) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.

(39) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(40) Filed as Exhibit 4b(2) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(41) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(42) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(43) Filed as Exhibit 4b(5) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(44) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(45) Filed as Exhibit 4 with Current Report on Form 8-A, File No. 001-00973 on June 1, 1991 and incorporated herein by this reference.

(46) Filed as Exhibit 4(i) with Current Report on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(47) Filed as Exhibit 4 with Current Report on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(48) Filed as Exhibit 4(i) with Current Report on Form 8-A, File No. 001-00973 on February 4, 1994 and incorporated herein by this reference.

(49) Filed as Exhibit 4 with Current Report on Form 8-A, File No. 001-00973 on March 15, 1994 and incorporated herein by this reference.

(50) Filed as Exhibit 4a(88) on Form 10-Q, File No. 001-00973 on November 8, 1994 and incorporated herein by this reference.

(51) Filed as Exhibit 4a(91) with Quarterly Report on Form 10-Q for the quarter ended September 30, 1994, File No. 001-00973, on November 8, 1994 and incorporated herein by this reference.

(52) Filed as Exhibit 4a(2) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.

(53) Filed as Exhibit 4a(3) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.

(54) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on May 15, 1998 and incorporated herein by this reference.

(55) Filed as Exhibit 4a(97) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-00973 on February 25, 2003 and incorporated herein by this reference.

(56) Filed as Exhibit 4a(98) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(57) Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(58) Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(59) Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(60) Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(61) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 001-00973 on August 3, 2004 and incorporated herein by this reference.

(62)

Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(63) Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(64) Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(65) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(66) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.

(67) Filed as Exhibit 4a(29) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.

(68) Filed as Exhibit 4a(30) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.

(69) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 001-00973 on October 29, 2010 and incorporated herein by reference.

(70) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(71) Filed as Exhibit 4.6 to Registration Statement on Form S-3, No. 333-76020 filed on December 27, 2001 and incorporated herein by this reference.

(72) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973 on February 19, 2009 and incorporated herein by reference.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED Schedule II Valuation and Qualifying Accounts Years Ended December 31, 2010 December 31, 2008

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe	Balance at End of Period
			Millions		
2010					
Allowance for Doubtful Accounts	$ 79	$ 99	$ 0	$ 110(A)	$ 68
Materials and Supplies Valuation Reserve	5	0	0	1(B)	4
Other Valuation Allowances	8	0	0	8(C)	0
2009					
Allowance for Doubtful Accounts	$ 66	$ 110	$ 0	$ 97(A)	$ 79
Materials and Supplies Valuation Reserve	5	1	0	1(B)	5
Other Valuation Allowances	8	0	0	0	8
2008					
Allowance for Doubtful Accounts	$ 46	$ 89	$ 0	$ 69(A)	$ 66
Materials and Supplies Valuation Reserve	6	0	0	1(B)	5
Other Valuation Allowances	8	0	0	0	8

(A) Accounts Receivable/Investments written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

(C) Valuation Allowance written off.

PSEG POWER LLC

Schedule II Valuation and Qualifying Accounts Years Ended December 31, 2010 December 31, 2008

Column A	Column B	Column C Additions		Column D	Collumn E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe	Balance at End of Period
			Millions		
2010					
Materials and Supplies Valuation Reserve	$ 5	$ 0	$ 0	$ 1(A)	$ 4
2009					
Materials and Supplies Valuation Reserve	$ 5	$ 1	$ 0	$ 1(A)	$ 5
2008					
Materials and Supplies Valuation Reserve	$ 6	$ 0	$ 0	$ 1(A)	$ 5

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule II Valuation and Qualifying Accounts Years Ended December 31, 2010 December 31, 2008

Column A	Column B	Column C Additions		Column D	Collumn E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe	Balance at End of Period
			Millions		
2010					
Allowance for Doubtful Accounts	$ 78	$ 99	$ 0	$ 110(A)	$ 67
2009					
Allowance for Doubtful Accounts	$ 65	$ 109	$ 0	$ 96(A)	$ 78
2008					
Allowance for Doubtful Accounts	$ 45	$ 89	$ 0	$ 69(A)	$ 65

(A) Accounts Receivable/Investments written off.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service
	PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a TPS.
BGS-Fixed Price	Basic Generation Service-Fixed Price
	Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service
	Mechanism approved by the BPU for NJ utilities to recover all its commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities
	Agency responsible for regulating pubic utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Competition Act	Electric Discount and Energy Competition Act
	New Jersey s 1999 Electric Utility Restructuring Legislation
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Deregulation	In the energy industry, the process by which regulated markets become competitive, giving customers the opportunity to choose their energy supplier
Distribution	The delivery of electricity to the retail customer s home, business or industrial facility through low voltage distribution lines
EDC	Electric Distribution Company
	A company that owns the power lines and equipment necessary to deliver purchased electricity to the customer

EMP	New Jersey Energy Master Plan
	Plan mandated by New Jersey statute to be developed by the BPU and other New Jersey policy-making agencies to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment
Energy Holdings	PSEG Energy Holdings L.L.C.
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
	A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	Federal Energy Regulatory Commission

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Term	Phrase/Description
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles
	Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
Greenhouse gas emissions	Gases (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the earth s atmosphere, increasing the mean global surface temperature of the earth
Grid	A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the electricity requirements of the customers connected to the grid at various points
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
Hope Creek	Hope Creek Nuclear Generating Station
ISO	Independent System Operator
	An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit
	A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets
LCAPP	Long-Term Capacity Agreement Pilot Program
	A new program established in January 2011 which provides for 2,000 MW of subsidized base load or mid-merit electric power generation in New Jersey.
Lifeline Program	A New Jersey social program for utility assistance that offers $225 per year to persons who meet the eligibility requirements
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates
	Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
MTM	Mark-to-Market
	Valuation of a security, commodity or financial instrument to reflect current resale values
NDT	Nuclear Decommissioning Trust
NEO	Named Executive Officer

	A term under the SEC s disclosure regulations designating a registrant s Chief Executive Officer, Chief Financial Officer and three other highest paid decision making managers
ISO-NE	New England Power Pool
	An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	Nuclear Regulatory Commission

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Term	**Phrase/Description**
NUG	Non-Utility Generation
	Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
Off peak	Periods of lower electrical demand
OPEB	Other Postretirement Benefits
	Benefits other than pensions payable to retirees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
Peach Bottom	Peach Bottom Atomic Power Station
Peak load	A measure of the amount of electricity required to be delivered during periods of highest demand
PJM	PJM Interconnection, L.L.C.
	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PRP	Potentially Responsible Parties
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated
Renewable Energy	Energy derived from resources that are regenerative or that can not be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with SFAS 71
Regulatory Liability	Costs recognized by a regulated utility company in accordance with SFAS 71
RGGI	Regional Greenhouse Gas Initiative
	The first mandatory, market-based effort in the U. S. to reduce greenhouse gas emissions; states will sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy, and other clean energy technologies
RMR	Reliability-Must-Run
	Designation of a power plant whose output is needed to maintain local reliability regardless of its operating cost or market price

RPM	Reliability Pricing Model
	A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
Salem	Salem Nuclear Generating Station
SBC	Societal Benefits Charges
SEC	U.S. Securities and Exchange Commission
Services	PSEG Services Corporation
Spill Act	New Jersey Spill Compensation and Control Act

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and
Chief Executive Officer

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2011
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2011
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 25, 2011
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 25, 2011
/s/ CONRAD K. HARPER **Conrad K. Harper**	Director	February 25, 2011
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 25, 2011
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2011
/s/ DAVID LILLEY	Director	February 25, 2011

David Lilley

/s/ THOMAS A. RENYI	Director	February 25, 2011

Thomas A. Renyi

/s/ HAK CHEOL SHIN	Director	February 25, 2011

Hak Cheol Shin

/s/ RICHARD J. SWIFT	Director	February 25, 2011

Richard J. Swift

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG Power LLC

By: /s/ William Levis
William Levis
President and
Chief Operating Officer

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ Ralph Izzo	Chairman of the Board and Chief Executive Officer and Director	February 25, 2011
Ralph Izzo	(Principal Executive Officer)	
/s/ Caroline Dorsa	Executive Vice President and Chief Financial Officer and Director	February 25, 2011
Caroline Dorsa	(Principal Financial Officer)	
/s/ Derek M. DiRisio	Vice President and Controller	February 25, 2011
Derek M. DiRisio	(Principal Accounting Officer)	
/s/ J.A. Bouknight, Jr.	Director	February 25, 2011
J.A. Bouknight, Jr.		
/s/ William Levis	Director	February 25, 2011
William Levis		
/s/ Randall E. Mehrberg	Director	February 25, 2011
Randall E. Mehrberg		
/s/ Eileen A. Moran	Director	February 25, 2011
Eileen A. Moran		

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2011
Ralph Izzo		
/s/ CAROLINE DORSA	Executive Vice President and Chief Financial Officer	February 25, 2011
Caroline Dorsa	(Principal Financial Officer)	
/s/ DEREK M. DIRISIO	Vice President and Controller	February 25, 2011
Derek M. DiRisio	(Principal Accounting Officer)	
/s/ ALBERT R. GAMPER, JR.	Director	February 25, 2011
Albert R. Gamper, Jr.		
/s/ CONRAD K. HARPER	Director	February 25, 2011
Conrad K. Harper		
/s/ RICHARD J. SWIFT	Director	February 25, 2011
Richard J. Swift		

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document*
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema*
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase*
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase*
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase*
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document*

b. Power:

Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32c:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code

c. PSE&G:

Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12c:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm
Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32e:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code

* XBRL information is furnished, not filed.