PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 27, 2012
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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, 2011,

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 x	No ¨
Public Service Electric and Gas Company	Yes x	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, 2011 was $16,495,247,274 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, 2012 was 506,050,478.

As of January 31, 2012, 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 2012 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 2, 2012, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management s beliefs as well as assumptions made by and information currently available to management. When used herein, the words anticipate, intend, estimate, believe, expect, plan, should, hypothetical, potential, 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 the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,

- 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 in the future, 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 our operations,

- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, 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 or the credit quality of our counterparties, including in our leveraged leases,

- 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,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- increase in competition in energy markets in which we compete,
- challenges associated with recruitment and /or retention of a qualified workforce,
- 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.

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 consequences to, or effects on, us or our business prospects, financial condition or results of operations that management expects. 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 apply only 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 210.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the 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.

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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 direct 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 formed 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.
	Has also implemented several programs to improve efficiencies in customer energy use and increase the level of renewable generation within New Jersey.	Also pursuing development of solar and other renewable generation projects.

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 (Losses) in millions	2011	2010	2009
Power	$ 1,002	$ 1,136	$ 1,191
PSE&G	521	359	325
Energy Holdings	(134)	49	72
Other	18	13	6

PSEG Income from Continuing Operations	**$ 1,407**	**$ 1,557**	**$ 1,594**

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

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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 and year to year thereafter.

About 46% 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.

How Power Operates

We own approximately 13,060 MW of generation capacity located in the Northeast and Mid Atlantic regions of the U.S. in some of the country s largest and most developed electricity markets.

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

In 2011, we sold 2,000 MW of generation facilities we owned and operated 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: 44% gas, 28% 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 2011 was approximately 54,000 GWh. The following table indicates the proportionate share of generating output by fuel type.

Generation by Fuel Type	**Actual 2011**
Nuclear:	
New Jersey facilities	38%
Pennsylvania facilities	18%
Fossil:	
Coal:	
New Jersey facilities	5%
Pennsylvania facilities	9%
Connecticut facilities	1%
Oil and Natural Gas:	
New Jersey facilities	22%
New York facilities	7%
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 34% base load, 43% load following and 23% 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. In 2011, our base load capacity factors were as follows:

Unit	2011 Capacity Factor
Nuclear	
Salem Unit 1	85.4%
Salem Unit 2	88.0%
Hope Creek	98.7%
Peach Bottom Unit 2	99.2%
Peach Bottom Unit 3	88.0%
Coal	
Keystone	75.1%
Conemaugh	72.7%

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

Load Following Units typically 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 typically operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system load) is satisfied. Base load units are dispatched first, with load following units next, followed by peaking units.

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 Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

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The following chart depicts the merit order of dispatch in PJM Interconnection L.L.C. (PJM), where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that 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 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.

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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.

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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 can be no assurance that such prices will remain in effect or 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 long-term operations would be adversely impacted since 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.

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 76 billion cubic feet.

Oil Oil is used as the primary fuel for one load following steam unit 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 2011 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 60 million people, nearly 19% of the total U.S. population and

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a peak demand of over 163,800 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 our generating stations operate in PJM.

New York The NYISO is the market coordinator for New York State and is 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. Our 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 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

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. Over the long-term, 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 our generating units fail to function effectively or otherwise become unavailable.

Over the past few 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 generating assets. 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.

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 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
June 2014 to May 2015	$ 136.50	$ 49.82

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 usually 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 the 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 and the other ISOs 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 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 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 serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2008-2011	2009-2012	2010-2013	2011-2014	2012-2015
PSE&G	$ 111.50	$ 103.72	$ 95.77	$ 94.30	$ 83.88
Jersey Central Power & Light	$ 114.09	$ 103.51	$ 95.17	$ 92.56	$ 81.76
Atlantic City Electric	$ 116.50	$ 105.36	$ 98.56	$ 100.95	$ 85.10
Rockland Electric Company	$ 120.49	$ 112.70	$ 103.32	$ 106.84	$ 92.51

A portion of our total capacity is hedged through the BGS auctions. On average, tranches won in the BGS auctions require 110 to 120 of capacity on a daily basis.

We have obtained price certainty for all of our PJM and New England capacity through May 2015 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

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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 was additional incentive for more of the smaller commercial and industrial electric customers to switch. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. While this impact has been reduced as average BGS rates have declined to a level more closely resembling current market prices, customers may still see an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or migration, will continue, but the impact on our results could be material.

As of February 9, 2012, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2014.

Base Load Generation	**2012**	**2013**	**2014**
Generation Sales	100%	85%-90%	30%-35%

Power s strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Power s nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements for the three years. Power also has various long-term fuel purchase commitments for coal to support its fossil generation stations. These purchase obligations are consistent with Power s strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units have historically provided a lower contribution to our margin than either the nuclear or coal units, although market price dynamics of coal and gas over the past few years have moderated this historical relationship.

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 6.2 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 competitive services, such as appliance repair. 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, our approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation Transmission Regulation.

Transmission Statistics

December 31, 2011		Historical Annual
Network Circuit Miles	**Billing Peak (MW)**	**Load Growth 2007-2011**
1,357	10,933	-0.3%

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 2011. 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 2011 Sales	
Customer Type	**Electric**	**Gas**
Commercial	57%	36%
Residential	33%	60%
Industrial	10%	4%
Total	**100%**	**100%**

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

Electric and Gas Distribution Statistics

	December 31, 2011		Historical Annual
	Number of Customers	**Electric Sales and Gas Sold and Transported**	**Load Growth 2007-2011**
Electric	2.2 Million	42,506 GWh	-0.5%
Gas	1.8 Million	3,527 Million Therms	2.2%

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Supply

Although commodity revenues make up almost 54% 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 are not served by 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 BGSS gas customers 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

Historically, there has been 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 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 generation projects. Energy Holdings is also continuing to explore opportunities for additional investments in renewable generation.

Over the past several years, we have terminated all of our international leveraged leases with lessees willing to meet certain economic thresholds in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing the majority of our previous international investments. We are continuing to explore options for our remaining international investment in Venezuela as well as our projects in Hawaii and New Hampshire. In February, 2012, the California Public Utilities Commission approved the shut down of GWF Power and we anticipate recovering the remaining book value of our investment. For additional information on these generation facilities, see Item 2. Properties.

Products and Services

The majority of our remaining $881 million of domestic lease investments are energy-related leveraged leases. As of December 31, 2011, the single largest lease investment represented 38% 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 on 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 United States (GAAP), the leveraged 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 own and operate solar projects in New Jersey, Florida and Ohio totaling 29 MW. See Item 2. Properties for additional information. In January 2012, Energy Holdings also acquired an additional 25 MW solar project currently under construction in Arizona. Completion of this project is expected by the third quarter of 2012. All of the energy, capacity and environmental attributes generated by the project in the first 20 years are expected to be sold under a long-term power purchase agreement. Energy Holdings has issued guarantees of up to $71.5 million for payment of obligations related to the construction of the project. These guarantees will terminate upon successful completion of the project. The total investment for the project will be approximately $75 million.

Also, in December 2011, the Long Island Power Authority (LIPA) selected PSEG Long Island LLC (PSEG LI), a newly formed wholly owned subsidiary of Energy Holdings, to manage its electric transmission and distribution system in Long Island, New York.

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LIPA issued a press release that it had selected us for a variety of reasons, including our proven track record of first quartile customer service and reliability, commitment to cost control, corporate culture of transparency and local decision making, technical expertise and proven environmental track record. The ten year contract will commence on January 1, 2014. As part of the management contract, PSEG LI will be expected to develop and implement a number of operational improvements to provide safe and reliable service for LIPA s customers, increase customer satisfaction and manage the operational and maintenance costs of LIPA.

COMPETITIVE ENVIRONMENT

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, 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, cost allocation and who is permitted to build transmission 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 New Jersey where a new law was enacted on January 28, 2011 establishing a long-term capacity agreement pilot program (LCAPP) which provides for up to 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. The lack of consistent rules in energy markets can negatively impact the competitiveness of our plants.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) 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 could increase over time. 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. FERC has also ordered all FERC-jurisdictional regions to consider public policy requirements, such as State Renewable Portfolio Standards, in their planning processes, which could facilitate the integration of renewable resources. For additional information, see the 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 contractual provisions that provide us a 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.

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.

EMPLOYEE RELATIONS

As of December 31, 2011, we had approximately 9,784 employees within our subsidiaries, including 6,346 covered under collective bargaining agreements. All of our collective bargaining agreements will expire on April 30, 2013 or later. We believe we maintain satisfactory relationships with our employees.

	Employees as of December 31, 2011			
	Power	**PSE&G**	**Energy Holdings**	**Services**
Non-Union	1,207	1,250	16	965
Union	1,492	4,845	0	9
Total Employees	**2,699**	**6,095**	**16**	**974**
Number of Union Groups	3	5	N/A	1

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 seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain 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 Regional Transmission Operators/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, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC and PSEG Nuclear LLC were each granted continued MBR authority from FERC in June 2011. Retention of MBR authority is important to the maintenance of our current generation business revenues.

- ***Cost-Based Reliability Must Run (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. In June 2011, we asked PJM to re-evaluate whether a previously approved extension of the RMR contract for Hudson 1 was necessary. In August 2011, PJM determined that such an extension was not needed and stated that it would be releasing the RMR contract. Accordingly, we filed with FERC to notify FERC that PJM had terminated RMR services from Hudson Unit 1 as of December 7, 2011. Also in September, we informed PJM that we were retiring the gas-fired load following Hudson Unit 1 as of December 8, 2011.

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.

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PJM 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 D.C. Circuit Court of Appeals issued a decision upholding the 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.

ISO-NE ISO-NE s market for installed capacity with all generators in New England provides fixed capacity payments. 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 ISO-NE continue to develop. We challenged in court the results of ISO-NE s first forward capacity auction, arguing that our units received inadequate compensation notwithstanding the location of our resources in a constrained area. The D.C. Circuit Court of Appeals recently ruled in our favor and remanded the proceeding to FERC. We and other generators have also filed a complaint at FERC regarding ISO-NE s capacity market design, alleging that it insufficiently reflects locational capacity values. FERC acted on the complaint, largely accepting the ISO-NE s capacity market design; however, this ruling is being appealed.

NYISO 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.

LCAPP In 2011, the State of New Jersey concluded that new natural-gas fired generation was needed and enacted the Long-Term Capacity Agreement Pilot Program Act (LCAPP Act) to subsidize 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA requires that the generator bid in and clear in the PJM RPM base residual auction in each year of the SOCA term in order to receive the subsidized payment. The SOCA requires each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers, calculated as the difference between the RPM clearing price for each year of the term and the guaranteed price for each generator as set forth in its respective SOCA. The EDCs, including PSE&G, were directed to enter into fifteen-year SOCAs with three generators selected by the BPU: CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc., Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, and New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc. Each of the New Jersey EDCs entered into the SOCAs as directed by the State, but did so under protest reserving their rights.

The NRG subsidiary filed a petition at the BPU claiming that there has been a material modification in PJM s RPM that will adversely affect its performance under the SOCA and asked the BPU for relief through modifications to its SOCA. In January 2012, PSE&G received a similar notice of dispute from another of the three selected generators. In February 2012, the BPU announced that it would consider the NRG dispute in a proceeding, which will be presided over by the BPU s president. The BPU indicated that it would encourage the CPV and Hess subsidiaries to also participate in the proceeding.

In 2011, the BPU also initiated a second proceeding, not authorized by the LCAPP Act, to consider whether there is a need for additional generation capacity in the state and whether there are rules or practices that inhibit the development of that generation in the competitive market. The BPU Staff issued written recommendations on these issues in December 2011 and recommended several options for the BPU to consider in the event that sufficient levels of new generation do not clear in the 2012 and 2013 RPM auctions. At this time, the BPU has not acted on the staff recommendations.

Legal challenges to the BPU s implementation of the LCAPP Act, as well as to the constitutionality of the LCAPP Act were filed and are pending.

Maryland is also considering similar subsidies to above-market new generation. In September 2011, the Maryland Public Utility Commission (PUC) issued an order requiring its EDCs to issue a Request for Proposals (RFP) to procure up to 1,500 MW of new natural gas-fired generation located in the Southwest MAAC electrical region. The RFP would require up to a 20-year contract, with ratepayers paying the generator a fixed capacity amount and would require the generator to bid into and clear the RPM auctions (similar to the LCAPP SOCA). Developments in Maryland may influence developments in New Jersey regarding the construction of subsidized generation and impact energy and capacity prices in PJM.

The impacts of the subsidized above-market contracts on RPM auction prices were mitigated, but not eliminated, when FERC ordered certain changes to the PJM Tariff, including a Minimum Offer Price Ruling (MOPR) that would restrict new generation from bidding in RPM at less than an established minimum level established by Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. The BPU, the Maryland PUC and other parties have challenged the FERC s MOPR order, and those challenges are pending.

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 2011 and Future Outlook.

Transmission Policy Developments In 2010, FERC initiated a Notice of Proposed Rulemaking (NOPR) proceeding to evaluate whether reforms were necessary to current transmission planning and cost allocation rules to stimulate additional transmission development. The rulemaking also addressed the issue of whether the right of first refusal (ROFR) contained in FERC-approved tariffs and contracts, under which incumbent transmission companies have a ROFR to build transmission located within their respective service territories, should be eliminated. On July 21, 2011, FERC issued a Final Rule (Order 1000) in this proceeding. The Final Rule, among other things (i) directs regional planners, such as PJM, to modify their planning processes to consider transmission needs driven by public policy requirements established by state or federal laws or regulations (ii) directs regional planners to remove the ROFR from its tariffs and agreements, subject to exceptions for certain types of projects and subject to a back-stop mechanism that may permit incumbent transmission owners to step in and build transmission if third party developers projects are delayed (iii) requires regional planners to develop regional cost allocation methodologies consistent with certain articulated principles, including that costs be roughly commensurate with project benefits and (iv) requires regional planners in neighboring regions to have a common interregional cost allocation method for new interregional facilities. We and many other parties to the proceeding have sought rehearing of the Final Rule, which remains pending. Ultimate judicial appeals are likely. PJM is about to commence a stakeholder process that will develop implementing details regarding Order 1000. An expected outcome of this Final Rule is the construction of more transmission through public policy planning and the opening up of transmission construction and ownership to third-party developers and to incumbents seeking to build outside of their service territories. We cannot predict the final outcome or impact on us; however, specific implementation of the Order 1000 in the various regions, including within our service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.

We are a party to a proceeding that is pending in US District Court in New Jersey challenging the constitutionality of LCAPP and a proceeding pending in the Appellate Division in New Jersey challenging the BPU s implementation of LCAPP.

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 Corporation (PPL) for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is $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 significant local opposition. Although the BPU has memorialized its approval in a written order and the New Jersey Department of Environmental Protection has approved construction of the portion of the project crossing the Highlands region, we have not received certain environmental approvals that are required for each of the Eastern and Western segments of the Susquehanna-Roseland line, including from the National Park Service (NPS). In November 2011, the NPS issued a draft Environmental Impact Statement (EIS) recommending a no action alternative that would require re-routing of the project around the affected federal park areas. We submitted comments on this draft EIS and are continuing to work with the NPS on mitigation as the agency prepares its final EIS. The NPS has also announced publicly that it intends to decide on its final preferred route in March 2012. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and for the Western segment is June 2015, although further delays are possible. Delays in the construction schedule could impact the timing of expected transmission revenues.

On February 3, 2011, certain environmental groups that were parties to the BPU proceeding approving the Susquehanna-Roseland line and that appealed the BPU s approval order 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. On January 12, 2012, the Appellate Division denied the motion. The underlying substantive appeal of the BPU approval order remains pending.

In October 2010, PJM approved the North East Grid project, a 230 kV project running from Roseland to Hudson. This project has an expected in-service date of June 2015 with an estimated cost of construction of $895 million. The North East Grid project was approved in place of a previously approved 500 kV Branchburg-Roseland-Hudson (B-R-H) project. On October 31, 2011, we filed a petition with FERC seeking Construction Work in Progress (CWIP) in rate base, 100% abandonment cost recovery and a 100 basis point ROE adder with respect to the project. Notwithstanding protests filed by the BPU and a group of state ratepayer advocates, including the New Jersey Division of Rate Counsel (Rate Counsel), FERC granted our request for CWIP in rate base and 100% abandonment cost recovery, along with a 25 basis point ROE adder, on December 31, 2011, effective January 1, 2012.

In its Regional Transmission Expansion Plan, PJM has approved our construction of several other 230 kV transmission projects. In April 2011, we filed a petition with FERC seeking incentive rates for five of these projects (Burlington-Camden project, North Central Reliability project, the Mickleton-Gloucester-Camden project, Middlesex Switch Rack project and Bayonne-Marion project). For each of these projects, we requested inclusion of 100% of CWIP in rate base and recovery of 100% of prudently incurred abandonment costs with an effective date of June 14, 2011. In June 2011, FERC granted the requested incentives for three of the projects (Burlington-Camden, North Central Reliability and Mickleton-Gloucester-Camden) with a total estimated capital investment of $1.0 billion, representing approximately 80% of our request.

In May 2011, we filed a petition with the BPU to site the North Central Reliability project. This project, which will involve upgrading certain circuits and switching stations from 138 kV to 230 kV, is currently estimated to cost $390 million and has an in-service date of June 2014. We expect the BPU to issue a decision in the first quarter of 2012.

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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 may not be available to companies building transmission in New Jersey, including us. The DOE is expected to issue a new Congestion Study in 2012.

PJM Transmission Rate Design In 2007, FERC addressed the issue of how transmission rates, paid by PJM transmission customers and ultimately paid by 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. PJM s Order 1000 stakeholder proceedings may also establish cost allocation rules regarding costs for transmission facilities in PJM.

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 generation assets were audited in 2011 and our utility assets will be audited in 2012. In addition, many of our operating companies have been subject to spot audits. NERC compliance represents a significant and challenging area of compliance responsibility for us. 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 in 2008. As part of this new legislation, the SEC and the CFTC will be implementing new rules to effectuate 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 swaps;
- defining swap dealers and major swap participants;
- the end-user exception from clearing requirements;

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- position limits;
- margin requirements;
- capital requirements; and
- reporting requirements.

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 issue them. A broad or less than clear definition of swap dealer could result in Power being classified as a dealer, which would impose significant reporting and record-keeping requirements as well as clearing/collateral requirements on Power unless we fall under the commercial end-user exemption recognized in the Dodd-Frank Act. We believe that any regulatory change that deviates from the original intent would need to be addressed by additional legislation.

The CFTC may issue a Final Rule on the definition of a swap dealer in the next month, which is expected to include a de minimis exemption. The CFTC is scheduled to issue a Final Rule on the definition of a swap in mid-2012.

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.

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. We received 20-year license extensions from the NRC for our Salem and Hope Creek facilities in June and July 2011, respectively. The current operating licenses of our nuclear facilities expire in the years shown below:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

In 2010, 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. The NRC acceptance review is complete and agency evaluation is underway. There were no petitions filed for permission to intervene. The current NRC schedule would likely result in issuance of the Early Site Permit in 2014. The Early Site Permit qualifies the site as an approved location for a new reactor for a period of 20 years but we are under no obligation to build.

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the NRC will be performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan will result in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants meet the stringent applicable design and safety specifications of the NRC.

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In July 2011, the NRC task force submitted a report on the first 90 days of its nuclear power plant review. The report contained various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. These recommendations include proposed requirements for upgraded seismic and flooding protection, strengthening plants ability to deal with prolonged loss of power and development of emergency plans for events involving multiple reactors. In October 2011, the NRC staff issued a document which provides for a prioritization of the task force recommendations. In December 2011, the NRC approved the staff s prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1) and to include filtration of boiling water reactor (BWR) primary containment vents, and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016. The NRC and staff s next steps are to obtain stakeholder input and issue specific requirements associated with the prioritized recommendations. The NRC is expected to provide detailed requirements for the highest priority Tier 1 safety recommendations in the first quarter of 2012 with the requirements for the remaining Tier 1 recommendations following in 2014 and 2016. The NRC is proposing to issue letters and orders to licensees and create new regulations over a six-to-52 month period to address the task force recommendations.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with its operational and safety reviews or any other regulatory or industry responses to the events in Japan.

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 various other states regulations due to our operations in those states.

Rates

Retail Gas Transportation Rates In July 2010, as part of our 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.

On December 16, 2010, the BPU approved a settlement that resolved all remaining issues in our base rate case.

The BPU also commenced a generic proceeding to evaluate the process and standards for all utilities to provide discounts to their gas delivery customers, culminating in the issuance of an order in 2011. We, along with the other New Jersey gas utilities, filed to implement tariffs with the BPU setting forth their individual processes by which customers can obtain discounts. Our tariff remains pending at the BPU although we expect the BPU to issue an order in the first quarter of 2012.

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

Rate Clause	2011 Revenue	(Over) Under Recovered Balance as of December 31, 2011
	Millions	
Energy Efficiency and Renewable Energy	$ 200	$ 8
Universal Service Fund (USF)	164	21
Social Programs	70	58
Remediation Adjustment Clause (RAC)	50	92
Total SBC	**484**	**179**
NGC	256	(5)
Gas Weather Normalization	0	2
RGGI Recovery Charge (RRC)	37	144
Total	**$ 777**	**$ 320**

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, the RAC, which covers the costs to clean up manufactured gas plants and the USF. In addition, the electric SBC includes a Social Programs component. All components include interest on both over and under recoveries.

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

Gas Weather Normalization Clause The purpose of this clause is to remove the gas earnings volatility caused by variations in the weather over the winter period. To the extent that the cumulative winter period is colder than normal, we 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.

RRC On October 1, 2010, we filed a petition for an increase in the RRC, seeking a revenue increase of approximately $18.7 million in electric revenue and $1.4 million in gas revenue on an annual basis. The filing sought to reset the RRC rate components for five programs including: Carbon Abatement, the Energy Efficiency Economic Stimulus Program, the Demand Response Program, Solar 4 All, and the Solar Loan II Program. These initiatives are intended to help New Jersey meet its New Jersey Energy Master Plan (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. In implementing these initiatives, we are allowed to recover the costs of these programs on an annual basis through a true-up mechanism.

A Decision and Order was issued by the BPU in December 2011 finalizing the 2009 Carbon Abatement Stipulated provisional rates of approximately $3.9 million on an annual basis. This Order also approved a stipulation regarding the October 2010 RRC filing which resulted in a net annual revenue increase of $18.7 million in the electric RRC rates while maintaining the gas RRC rates at the current level.

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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, 2011, the State s electric and gas utilities filed to reset the statewide rates for the USF and Lifeline programs. The filed rates were subsequently updated and approved in a written order effective November 1, 2011. The approved USF rates are set to recover $242 million on a statewide basis. Of this amount, the electric rates are set to recover $185 million and the gas rates $57 million. The rates for the Lifeline program are set to recover $49 million and $22 million for electric and gas, respectively. We earn no margin on collection of the USF and Lifeline programs, resulting in no impact on Net Income.

SBC/NGC In August 2010, we made our 2010 annual SBC/NGC filing requesting an $85.4 million electric increase and a $17.2 million gas decrease. On February 11, 2011, we filed a stipulation of settlement with the Administrative Law Judge (ALJ). The stipulation was executed by all parties and allows us to increase electric SBC/NGC rates by $85.4 million and decrease gas SBC rates by $17.2 million, both on an annual basis. The stipulation was approved by the ALJ and adopted by the BPU by written order dated March 9, 2011, with rates effective April 1, 2011.

RAC 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. In May 2011, a settlement was signed by the parties and filed with the ALJ for the requested amounts. Also in May 2011, the ALJ issued an Initial Decision adopting the executed stipulation of the parties to the proceeding. The ALJ s Initial Decision was approved by the BPU in June 2011. New rates were effective July 1, 2011.

In November 2011, we filed a RAC 19 petition with the BPU requesting a decrease in electric and gas RAC revenues on an annual basis of $8.9 million and $10.1 million, respectively. We are seeking an Order by April 2012 and are currently in the discovery phase of the proceeding.

Connecticut Contract for Differences On December 1, 2011, PSEG New Haven LLC filed its first annual retail generation rate contested case seeking establishment of its first year (2012) revenue requirements of $16.7 million. As part of this process, an audit was performed by the Connecticut Public Utilities Regulatory Authority and the Office of Consumer Counsel in January 2012. Evidentiary hearings are scheduled for March 2012 with an expected Final Decision in May 2012.

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.

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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:

	2009	2010	2011	2012
36 Month Terms Ending	May 2012	May 2013	May 2014	May 2015(A)
Eligible Load (MW)	2,900	2,800	2,800	2,900
$ per kWh	0.10372	0.09577	0.09430	0.08388

(A) Prices set in the February 2012 BGS Auction will be effective on June 1, 2012 when the 2009 BGS agreements expire.

The BPU once again approved the auction process for 2012 with no significant changes to the process. However, as part of the BPU Order, the BPU Staff was directed to initiate a proceeding to review aspects of the BGS procurement process at the conclusion of the 2012 procurement, with an expected resolution by the end of May 2012.

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.

On June 1, 2011, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $16.1 million, excluding sales and use tax, to be effective October 1, 2011. This represented a reduction of approximately 1.1% for a typical residential gas heating customer. On September 22, 2011, the BPU approved the Stipulation of the parties, which implemented the filed BGSS rate, on a provisional basis, effective October 1, 2011.

On November 21, 2011, PSE&G provided notice to the BPU of a decrease in its BGSS-Residential Gas (RSG) Commodity Charge to be effective December 1, 2011. The self-implementing rate decrease was designed to bring a projected over collected balance of $56 million to zero by the end of September 2012. The annual impact of the decrease for the average residential heating customer is approximately 4.6%. On January 18, 2012, PSE&G provided notice to the BPU of another self-implementing one-month bill credit of 15 cents per therm (including sales and use tax) for its BGSS-Residential Gas customers to be effective February 1 through February 29, 2012.

PSE&G had executed a Stipulation between the parties which would make the current provisional BGSS rate final and resolve all issues of the proceeding. The Stipulation was sent to the Office of Administrative Law and upon being signed, will be sent to the BPU.

Energy Policy

New Jersey 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 December 2011.

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The 2011 EMP places an emphasis on expanding in-state electricity resources and reducing energy costs. The plan also recognizes the impact of climate change and accepts the previously set goal of a 22.5% target for the renewable portfolio standard (RPS) in 2021. It also references a goal that 70% of New Jersey s energy supplies should be from clean energy sources by 2050. To meet this goal, the plan redefines clean energy to include nuclear, natural gas and hydro power along with defined renewable sources and proposes a number of changes aimed at reducing the cost of achieving the 22.5% goal.

Specific program initiatives in the EMP include:

- construction of new combined cycle natural gas plants through the implementation of LCAPP, with the continued State challenge to FERC and PJM policies on market pricing rules in the capacity market;
- support for construction of new nuclear generation;
- changes to the solar program to reduce cost, expand opportunities, expand transparency and ensure economic and environmental benefits;
- expanded natural gas use to meet energy needs;
- development of decentralized combined heat and power;
- redesign of the delivery of state energy efficiency programs, and
- continued support for implementation of off-shore wind, without setting a specific capacity goal.

Solar Initiatives In order to spur investment in solar power in New Jersey and meet renewable energy goals, we have undertaken two major initiatives at PSE&G.

- **Solar Loans:** The first program helps finance the installation of 81 MW of solar systems throughout our electric service area by providing loans to customers. 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 is expected to be between $200 million and $250 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2011, we have provided a total of $127 million in loans for 518 projects representing 38 MW.

- **Solar 4 All:** The second solar initiative is the Solar 4 All Program under which we are investing approximately $451 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of centralized solar systems 500kW or greater installed on PSE&G-owned property and third-party sites in our electric service territory (40 MW) and solar panels installed on distribution system poles (40 MW). We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition we sell any SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales are used to offset program costs.

As of December 31, 2011, 26 MW of solar panels had been installed on approximately 120,000 distribution poles with an investment of approximately $185 million. In addition during 2011, 33 MW of centralized solar systems representing 19 projects were placed in service with an investment of approximately $160 million. An additional 6 MW is expected to be placed into service in the first quarter of 2012 and additional projects are in various stages of negotiation and development.

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On January 18, 2012, the BPU issued an order indicating that it will conduct a proceeding to address the proposed placement of solar panels on the poles. A negative determination by the BPU could impact our ability to complete the Solar 4 All pole mounted installations.

Solar Generic Proceeding The BPU is conducting a generic proceeding to examine whether existing utility rate-based solar programs, including ours, should be expanded, modified or discontinued once the current programs expire or the authorized level of solar installations has been achieved. Although the current programs are not expected to be affected, the proceeding will examine the costs and benefits of all of these programs. The proceeding is expected to conclude in the first quarter of 2012 with BPU Staff recommendations to the BPU, which may then be reflected in an order. We have advocated for expansion of our solar investment programs as part of this proceeding.

Capital Infrastructure Programs (CIP I and CIP II) We have received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the State s economy through the creation of new jobs. The original CIP I program, approved in 2009, included 38 qualifying projects totaling $694 million of investment. In July 2011, the BPU approved CIP II which included an additional 30 qualifying projects totaling approximately $78 million and $195 million in expenditures for gas and electric, respectively. The CIP II program investments are to be completed and placed in service by December 2012.

In conjunction with the approval of CIP II, we agreed to additional base spending of approximately $96 million, excluding new business for the period 2011 through 2013.

The CIP programs require periodic filings to implement the rates to recover investment costs at which times the BPU reviews the prudency of the implementation of the programs. CIP I was completed in June 2011 and in September 2011, we filed a final CIP I petition for $60 million in revenue requirements to roll the remaining projects into base rates. An Order is expected in 2012. In November 2011, we filed our first annual recovery petition for CIP II for the period ending December 31, 2011.

LCAPP See Federal Regulation Capacity Market Issues above.

Storm Damage Recovery On August 26, 2011, we filed a petition with the BPU requesting permission to defer incremental storm related costs and the opportunity to seek recovery in our next base rate proceeding. This proceeding remains pending. We have deferred approximately $29 million in incremental Operation and Maintenance (O&M) storm costs associated with Hurricane Irene. In addition, we deferred approximately $31 million in incremental O&M related to a severe October 2011 snow storm.

BPU Audits

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. In 2011, we received a full draft audit report, which included recommendations for changes in practices at PSE&G and its affiliates. We have provided comments back to the auditors on all chapters of the report. The BPU may enforce the recommendations in whole or in part by Order.

BPU Investigations

RRC/CIP In January 2012, the Rate Counsel filed a letter with the BPU requesting the BPU to take prompt action to investigate certain allegations of wrong doing in PSE&G s Solar 4 All, Energy Efficiency Economic Stimulus, and CIP I programs that were raised by three ex-employees in a lawsuit filed on December 20, 2011. At a public meeting on January 18, 2012, the BPU indicated that it would seek to obtain certain pertinent information from PSE&G prior to determining whether an investigation was warranted.

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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, but may be material.

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 Item 8. Financial Statements and Supplementary Data 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 our estimates of capital expenditures.

New Jersey Nitrogen Oxide (NO_x) Regulation: High Electric Demand Day In April 2009, the New Jersey Department of Environmental Protection (NJDEP) finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel fired electric generation units. The rule will have an impact on our generation fleet, as it imposes NO_x emissions limits that require capital investment for controls or the retirement of up to 102 combustion turbines (approximately 2,000 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 2015. We are currently evaluating our compliance options.

Connecticut NO_x Regulation Under current Connecticut regulations, Power s Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NOx emission limitations that were incorporated into the facilities operating permits. In 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.

Hazardous Air Pollutants Regulation In accordance with a court ruling, the United States Environmental Protection Agency (EPA) proposed a Maximum Achievable Control Technology (MACT) regulation in March 2011 which was finalized on December 21, 2011. This regulation includes requirements related to the reduction of mercury and other hazardous air pollutants from emissions pursuant to the CAA. The impact to our fossil generation fleet is currently being determined but we believe the back-end technology environmental controls recently installed at our Hudson and Mercer coal facilities should meet the rule s requirements. Some additional controls could be necessary at our Connecticut facility, pending engineering evaluation. The impact to our jointly-owned coal fired generating facilities in Pennsylvania is under evaluation. In December 2011, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic

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Reduction (SCR) systems at our jointly-owned coal fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the fourth quarter of 2014. PSEG s share of this investment is approximately $147 million.

Cross-State Air Pollution Rule (CSAPR) On July 6, 2011, the EPA issued the final CSAPR. CSAPR limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS). Technical revisions to the CSAPR were finalized on February 7, 2012. The EPA increased New Jersey s allocation of annual NOx and ozone season NOx allowances beyond what was proposed. The EPA also finalized the increase in New Jersey s allocation of SO_2 allowances from the October proposal. The additional increases in NOx allocations are favorable to PSEG, since both PSEG and New Jersey as a whole are projected to be very tight on NOx allowances (both ozone season and annual).

On December 30, 2011, the United States Court of Appeals for the D.C. circuit issued a ruling to stay CSAPR pending judicial review. Until a final decision is reached, the court has ordered that the existing Clean Air Interstate Rule (CAIR) requirements continue temporarily. We have intervened in the CSAPR litigation along with other generating companies in support of the rule.

The continuation of CAIR affects our generating stations in Connecticut, New Jersey and New York. The purpose of CAIR is to improve Ozone and Fine Particulate (PM2.5) air quality within states that have not demonstrated achievement of the 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 2012 operations are similar to those in the past three years, it is expected that the impact to operations from the temporary implementation of CAIR in 2012 will not be significant.

We continue to evaluate the impact of CSAPR on us due to many of the uncertainties that still exist regarding implementation. As we have made major capital investments over the past several years to lower the SO_2 and NO_x emissions of our fossil plants in the states affected by CSAPR (New Jersey, New York and Pennsylvania), we do not currently foresee the need to make significant additional expenditures to our generation fleet to comply with CSAPR. As such, we currently anticipate that this rule will not have a material adverse impact to our capital investment program or units operations.

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, originally established RGGI 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.

Applicable 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 compliance period.

Pricing for the allowances vary based on future allowance market conditions and electric generation market conditions. For the first three-year compliance period, we have acquired sufficient allowances to compensate for CO_2 emissions from affected sources.

In May 2011, the Governor of New Jersey announced his intent to withdraw New Jersey from RGGI beginning in 2012. Therefore, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances, but our generation facilities in New York and Connecticut remain subject to RGGI.

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

***CO_2 Regulation Under the* 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 was scheduled to take effect in January 2011. In May 2010, the EPA finalized a Tailoring Rule that would 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.

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 define 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 new and existing power plants and refineries. The EPA has missed the date for release of a draft rule. We expect the EPA to put forth draft rules for new sources early in 2012. Since a proposed rule has not been published, the outcome of the rulemaking and its significance to us 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. Provisions of any new proposal 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 us 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.

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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 (BTA) 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. In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule.

In April 2011, the EPA published a new proposed rule which did not establish any particular technology as the BTA (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than 2 million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. Although the EPA has recently stated that a revision of the proposed rule to include an alternative framework for compliance is currently being considered, if the rule were to be adopted as proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Note 13. Commitments and Contingent Liabilities for additional information.

Hazardous Substance Liability

The production and delivery of electricity, the 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, although such impacts could be material.

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 of 1982 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 March 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit seeking suspension of the Nuclear Waste Fee. The suit was filed in the U.S. Court of Appeals for the D.C Circuit.

The Nuclear Waste Fee litigation is not expected to have any effect on our September 2009 settlement agreement with DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE delay in accepting spent nuclear fuel for permanent disposition. 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. 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 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. The EPA has not established a date for release of a final rule.

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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.

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, including mandatory NERC and cybersecurity 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 with all applicable rules, we cannot predict the outcome of such audits.

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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 few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One of the reasons for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economical to run certain of our gas units than our coal units.

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.

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, 2011, it may have had to provide approximately $812 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the CFTC which are expected to be implemented in 2012.

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.

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.

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

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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 significant increases in 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, each of 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 are developing or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the northeast. RGGI member states control emissions of GHG by issuance of allowances to emit CO_2 primarily through an auction. New Jersey announced that it is withdrawing from RGGI beginning in 2012.

A portion of our fossil fuel-fired electric generation is located in Connecticut and New York, which are within the RGGI region. The costs or inability to purchase CO_2 allowances for our fleet operating within a RGGI state could place us at an economic disadvantage compared to our competitors not located in a RGGI state.

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

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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 issued a proposed rule in 2011 regarding regulation of cooling water intake structures. If adopted as proposed, 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. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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 discharged 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 NAAQS 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 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. 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. The EPA has not established a date for release of a final rule.

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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 2033 through 2046.

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 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 subsidized base load or mid-merit electric power generation. The LCAPP may have the effect

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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 could 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.

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, FERC has issued a rule that requires changes to transmission planning processes so that more transmission can be built to facilitate renewable generation development. This rule has also opened up the construction of transmission to competition. In addition, the DOE-funded Eastern Interconnection Planning Collaborative (EIPC) continues its efforts to study transmission planning across the Eastern Interconnection, evaluating the extent to which the construction of large-scale transmission is needed.

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.

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,

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- 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, micro turbines, 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 our 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.

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.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition, results of operations and cash flows.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset s carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

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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 external financings. 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.

Financial 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 financial 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.

We may be adversely affected by equipment failures, accidents, severe weather events 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, severe weather events 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.

Acts of war, terrorism or cybersecurity breaches 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 and information management systems for customer-related operations, could be direct or indirect targets or be affected by terrorist or other criminal activity.

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Our businesses could also be impacted by cybersecurity breaches. Cybersecurity threats include:

- operational interference, such as attacks on our generation facilities, transmission lines or the power grid;
- information theft as to employees and/or customers, such as personal financial and health records; and
- business system interruption or compromise.

Such events could severely disrupt business operations and result in loss of service to customers. These events could also result in significant expenses to repair security breaches or system damage as well as increased capital, insurance and operating costs, including increased security costs for our facilities. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

The BPU has issued an order, effective January 2012, in which it directed New Jersey utilities to outline what equipment and safety measures they have in place to monitor against cyber intrusions and to report any incidents.

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 operating performance.

One of the key elements to achieving the results in our business plan 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, severe storms, 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.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

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.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The 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, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances. For additional information relating to these leases, see Item 7. MD&A Critical Accounting Estimates and Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables.

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

Power

As of December 31, 2011, Power s share of summer installed generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	608	100%	608	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	383	100%	383	Coal	Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**5,946**		**3,300**		
Nuclear:						
Hope Creek	NJ	1,173	100%	1,173	Nuclear	Base Load
Salem 1 & 2	NJ	2,326	57%	1,336	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,247	50%	1,123	Nuclear	Base Load
Total Nuclear		**5,746**		**3,632**		
Combined Cycle:						
Bergen	NJ	1,178	100%	1,178	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	754	100%	754	Gas	Load Following
Total Combined Cycle		**3,162**		**3,162**		
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	340	100%	340	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	18	100%	18	Oil	Peaking
Total Combustion Turbine		**2,782**		**2,766**		
Pumped Storage:						
Yards Creek (C)	NJ	400	50%	200		Peaking
Total Operating Power		**18,036**		**13,060**		

Plants

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation

(C) Operated by Jersey Central Power & Light Company

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PSE&G

As of December 31, 2011, PSE&G had 58 MW of installed solar capacity in various towns throughout New Jersey.

Energy Holdings

Energy Holdings had investments in the following generation facilities as of December 31, 2011:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
United States					
Kalaeloa	HI	209	50%	105	Oil
GWF (A)	CA	105	50%	53	Petroleum coke
Bridgewater	NH	16	40%	6	Biomass
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Total United States		**359**		**193**	
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		**519**		**257**	

(A) In February, 2012, the California Public Utilities Commission approved the shut down of GWF Power.

Transmission and Distribution Facilities

As of December 31, 2011, PSE&G s electric transmission and distribution system included 23,553 circuit miles, of which 8,163 circuit miles were underground, and 836,465 poles, of which 546,129 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2011, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2011, 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 2,790,500 therms (270,922,330 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	670,500

Camden LPG	Camden, NJ	320,000
Central LPG	Edison Twp., NJ	900,000
Harrison LPG	Harrison, NJ	900,000
Total		**2,790,500**

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As of December 31, 2011, PSE&G owned and operated 17,710 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, all in four 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, 2011, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 23,898 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, including 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.

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 sought rehearing of the FERC approval order, which FERC denied in an order issued on April 8, 2011. The party then appealed this decision to the D.C. Circuit Court of Appeals. This appeal is pending.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Claim made in 1985 by the U.S. Department of the Interior under CERCLA with respect to the Pennsylvania Avenue and Fountain Avenue municipal landfills in Brooklyn, New York, for damages to natural resources. The U.S. Government alleges damages of approximately $200 million. To PSE&G s knowledge there has been no action on this matter since 1988.

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

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

(4) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document 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 2018 at an estimated cost of $2.8 million.

(5) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G s Trenton Switching Station property. 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

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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.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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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, 2011, there were 78,280 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2006 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.

	2006	2007	2008	2009	2010	2011
PSEG	$ 100.00	$ 151.93	$ 93.51	$ 111.14	$ 111.05	$ 120.15
S&P 500	$ 100.00	$ 105.48	$ 66.52	$ 84.07	$ 96.71	$ 98.76
DJ Utilities	$ 100.00	$ 120.06	$ 86.70	$ 97.47	$ 103.75	$ 124.08
S&P Electrics	$ 100.00	$ 123.07	$ 91.33	$ 94.38	$ 97.61	$ 118.05

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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
2011			
First Quarter	$ 33.12	$ 30.15	$ 0.3425
Second Quarter	$ 34.22	$ 30.30	$ 0.3425
Third Quarter	$ 35.48	$ 27.97	$ 0.3425
Fourth Quarter	$ 34.96	$ 30.60	$ 0.3425
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

On February 21, 2012, our Board of Directors approved $0.3550 per share of common stock dividend for the first quarter of 2012. This reflects an indicated annual dividend rate of $1.42 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 2011:

Three Months Ended December 31, 2011	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	0	$ 0.00
November 1-November 30	50,117	$ 33.66
December 1-December 31	27,000	$ 32.40

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2011:

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	3,272,300	$ 32.78	17,564,232(A)
Equity compensation plans not approved by security holders	0	$ 0.00	3,589,032(B)
Total	**3,272,300**	**$ 32.78**	**21,153,264**

(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 2011 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 2011 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

	2011	2010	2009	2008	2007
For the Years Ended December 31:		Millions, where applicable			
Operating Revenues	$ 11,079	$ 11,793	$ 12,035	$ 12,609	$ 12,051
Income from Continuing Operations (A)	$ 1,407	$ 1,557	$ 1,594	$ 918	$ 1,274
Net Income	$ 1,503	$ 1,564	$ 1,592	$ 1,188	$ 1,335
Earnings per Share:					
Income from Continuing Operations					
Basic(A)	$ 2.78	$ 3.08	$ 3.15	$ 1.81	$ 2.51
Diluted(A)	$ 2.77	$ 3.07	$ 3.14	$ 1.81	$ 2.50
Net Income					
Basic	$ 2.97	$ 3.09	$ 3.15	$ 2.34	$ 2.63
Diluted	$ 2.96	$ 3.08	$ 3.14	$ 2.34	$ 2.62
Dividends Declared per Share	$ 1.37	$ 1.37	$ 1.33	$ 1.29	$ 1.17
As of December 31:					
Total Assets	$ 29,821	$ 29,909	$ 28,678	$ 29,049	$ 28,299
Long-Term Obligations (B)	$ 7,482	$ 7,847	$ 7,679	$ 8,044	$ 8,709

(A) Income from Continuing Operations for 2011 and 2008 includes after-tax charges of $170 million and $490 million, respectively, related to certain leveraged leases.

(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 United States,

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

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

Our business discussion in Item 1 provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. 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 2011 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 2011 AND FUTURE OUTLOOK

During 2011, our results continued to be adversely impacted by lower prices for electricity and natural gas in the markets we serve. We began experiencing a greater pricing impact due to a decline in both PJM Reliability Pricing Model (RPM) and Basic Generation Service (BGS) rates which became effective in the second quarter. Our pricing also continues to be affected by customer migration away from our BGS supply contracts as these volumes are replaced with lower priced spot market sales. While the effect of customer migration on our results has been reduced as average BGS rates have been declining to a level more closely resembling current market prices, customers may still see an incentive to switch to third party suppliers. The result of such a switch may affect the price we receive on our sales, shifting from BGS rates that are established in auctions that have taken place over the past three years, to prices offered by third party suppliers which may be more representative of recent market pricing.

Partially offsetting this lower commodity pricing are higher revenues due to increased distribution rates at PSE&G as a result of the base rate case settlement in mid-2010. This 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%. We have also realized an increase in transmission revenues as a result of our 2011 Formula Rate Update which provided for approximately $45 million in increased revenues in our 2011 transmission rates effective January 1, 2011. We filed our 2012 Annual Formula Rate Update with FERC in October 2011, which provides for approximately $94 million in increased annual transmission revenues effective January 1, 2012.

These increased delivery charges have been offset by lower supply costs. The reduction in supply costs allows us to invest in infrastructure improvements without raising customer rates. Since January 2010, PSE&G s typical average residential customers who purchased supply from PSE&G have seen a total annual bill reduction of 19% for gas and 1% for electric.

For 2012 and beyond, the key issues our business will confront include:

- the continuing potential for sustained lower natural gas and electricity prices,

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uncertainty in the economic recovery,

regulatory and political uncertainty, particularly with regard to future energy policy, transmission policy and environmental regulation, and

challenges to competitive markets, including support for subsidized generation in many states, particularly in 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:

continue to focus on controlling costs while maintaining our safety, reliability and compliance standards,

successfully recontract our open supply positions, and

execute our capital investment program, including investments for growth that yield contemporaneous and attractive risk adjusted returns.

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 2011, the State of New Jersey enacted the Long-Term Capacity Agreement Pilot Program Act (LCAPP Act) to subsidize up to 2,000 MW of new natural gas-fired generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) by New Jersey EDCs, including PSE&G, to generators selected by the BPU. Legal challenges to the BPU s implementation of the LCAPP Act, as well as to the constitutionality of the LCAPP Act were filed and are pending.

Maryland is also considering similar subsidies to above-market new generation. In September 2011, the Maryland Public Utility Commission (PUC) issued an order requiring its EDCs to issue a Request for Proposals (RFP) to procure up to 1,500 MW of new natural gas-fired generation located in the Southwest MAAC electrical region. The RFP is similar to the LCAPP SOCA. These developments in Maryland could impact energy and capacity prices in PJM and may also impact developments in New Jersey regarding the construction of subsidized generation.

The LCAPP, Maryland s RFP or similar activity in other states may artificially depress prices in the competitive wholesale market and have the potential to harm competitive markets, on both a short-term and long-term basis. The lack of consistent rules in energy markets can adversely impact the competitiveness of our plants.

See Item 1. Business, Federal Regulation, FERC Capacity Market Issues for further information.

The United States Environmental Protection Agency (EPA) published a proposed rule in April 2011 related to 316(b) Clean Water Act requirements. The rule, as proposed, would establish a marine life mortality standard for certain existing cooling water intake structures. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take or the effect, if any, that they may have on our future capital requirements, financial condition or results of operations.

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) that limits power plant emissions in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions would have been governed by this rule beginning on January 1, 2012 for Sulfur Dioxide (SO_2) and annual Nitrogen Oxide

(NO_x) and May 1, 2012 for Ozone season NO_x. Certain states would have been required to make additional SO_2 reductions in 2014. The EPA issued draft technical adjustments to the final CSAPR in October 2011. CSAPR is generally expected to have an upward impact on electricity prices, resulting from the retirement of some units, as well as from the potential cost increase from either the purchase of allowances or the cost of operation of emissions control equipment. Technical revisions to the CSAPR were finalized on February 7, 2012. The EPA increased New Jersey s allocation of annual NO_X and ozone season NO_X allowances beyond what was proposed. The EPA also finalized the increase in New Jersey s allocation of SO_2 allowances from the October proposal. The additional increases in NOx allocations are favorable to PSEG, since both PSEG and New Jersey as a whole are projected to be very tight on NOx allowances (both ozone season and annual).

On December 30, 2011, the United States Court of Appeals for the D.C. Circuit issued a ruling to stay CSAPR pending judicial review. Until a final decision is reached, the court has ordered that the Clean Air Interstate Rule (CAIR) requirements continue temporarily. We have intervened in this litigation, along with other generating companies, in support of the EPA. The continuation of CAIR affects our generating stations in Connecticut, New Jersey and New York. If 2012 operations are similar to those in the past three years, the impact to our operations from the temporary implementation of CAIR in 2012 is not expected to be significant.

The EPA proposed a Maximum Achievable Control Technology (MACT) regulation in March 2011 which was finalized on December 21, 2011. This regulation prescribes reduced levels of mercury and other hazardous air pollutants pursuant to the Clean Air Act.

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the Nuclear Regulatory Commission (NRC) has been performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan will result in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants meet the stringent applicable design and safety specifications of the NRC.

We received our requested 20-year license extensions for the Salem and Hope Creek facilities in June and July 2011, respectively. Salem Units 1 and 2 are now licensed through 2036 and 2040, respectively, and Hope Creek is now licensed through 2046. Peach Bottom Units 2 and 3 are currently licensed through 2033 and 2034, respectively.

During 2011, the SEC and the Commodity Futures Trading Commission (CFTC) continued efforts enact stricter regulation over swaps and derivatives. The CFTC has issued Notices of Proposed Rulemakings (NOPRs) on many of the key issues. We cannot assess the exact scope of the new rules until they are issued by the SEC and CFTC. 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.

In December 2011, New Jersey released its revised Energy Master Plan (EMP) which contains a number of policy recommendations that the State can be expected to pursue through legislative and regulatory responses. The policy recommendations supporting nuclear power, solar and wind energy, energy efficiency and natural gas infrastructure are generally favorable to our business.

On July 21, 2011, FERC issued a Final Rule which, among other things directs regional planners such as PJM to (i) consider public policy requirements in planning new transmission, (ii) remove the Right of First Refusal (ROFR) which permits incumbent transmission owners, like us, the first opportunity to construct transmission within their respective service territories from its tariffs and agreements, subject to certain exceptions, and (iii) allocate costs for transmission projects in a way that roughly matches costs with benefits, while leaving flexibility to the regions to determine precise cost allocation methodologies. We cannot predict the final outcome or impact on us; however, specific implementation of the Final Rule in the various regions, including within our utility service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.

Operational Excellence

Our nuclear and fossil facilities continued their strong operating performance through the fourth quarter. Our nuclear units have achieved a capacity factor of 93% for the year and our combined cycle units have continued to improve their forced outage rates. Our generation fleet performed well during the July and August heat waves. During Hurricane Irene, the Salem and Hope Creek nuclear stations remained online. Overall, generation volumes for the year 2011 were 54.0 TWh, approximately 5% lower than in 2010 due primarily to reduced demands.

In addition, we continued to demonstrate system reliability by limiting customer outages. In February 2011, our service territory experienced winter storms that affected the electric transmission and distribution systems due to heavy icing and salt spray and in March 2011, our northern gas service territory was impacted by two heavy rainstorms that resulted in widespread flooding. Our personnel were prepared in each case for widespread outages and, as a result, were able to minimize the length of time our customers were without electric or gas service.

In August 2011, Hurricane Irene caused severe damage that resulted in flooding throughout our service territory, disrupting service to over 800,000 customers. With the assistance of mutual aid crews from other utilities, our associates worked to fully restore service to the majority of our customers within five days. In October 2011, a wet heavy snow storm caused extensive tree and power line damage, disrupting service to over 570,000 customers. By seeking the assistance of other utilities, as well as hiring a significant number of contractor power line and tree crews, we restored power to most of our customers within seven days. We filed a petition with the BPU asking permission to defer the incremental storm related costs and the opportunity to seek recovery in our next base rate proceeding. We have deferred approximately $60 million of incremental Operation and Maintenance (O&M) storm costs associated with Hurricane Irene and the October snow storm.

In December 2011, the Long Island Power Authority (LIPA) selected PSEG Long Island LLC (PSEG LI), a newly formed wholly owned subsidiary of Energy Holdings, to manage its electric transmission and distribution system in Long Island, New York. LIPA issued a press release that it had selected us for a variety of reasons, including our proven track record of first quartile customer service and reliability, commitment to cost control, corporate culture of transparency and local decision making, technical expertise and proven environmental track record. The ten year contract commences January 1, 2014, after LIPA s current contract with another party for utility services management expires. As part of the management contract, PSEG LI will be expected to develop and implement a number of operational improvements to provide safe and reliable service for LIPA s customers, increase customer satisfaction, and manage the operational and maintenance costs of LIPA.

On January 31, 2012, we entered into a specific matter closing agreement settling our dispute with the IRS over certain challenged lease transactions. This agreement settles the leasing dispute with finality for all tax periods in which we realized tax deductions from these transactions. In addition, we signed a settlement agreement covering all audit issues for tax years 1997 through 2003. We believe that there will be no material impact on earnings as a result of these settlement agreements. For additional information, see Note 13. Commitments and Contingent Liabilities.

Financial Strength

For 2011, our cash from operations was over $3.5 billion. Cash from operations for the year has benefited from two federal tax provisions enacted in 2010 which generated a total of approximately $900 million of cash benefits for us through accelerated depreciation. See Note 20. Income Taxes for additional information. These funds, combined with proceeds from asset sales, were used to support our capital expenditures, dividend payments and pension funding for the year. During 2011, we made approximately $2.1 billion in capital expenditures and paid dividends of $693 million. On February 21, 2012, our Board of Directors approved a $0.3550 per share common stock dividend for the first quarter of 2012. This reflects an indicated annual dividend rate of $1.42 per share. The Board s approval represents a change in our dividend policy moving from a strict earnings payout based approach to one that takes into consideration the growing contribution to earnings and cash from our regulated operations and continued cash flow from our generation business.

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We made our entire planned pension and OPEB contributions for the year 2011 of $426 million and, as of December 31, 2011, we had funded approximately 84% of our projected benefit obligation. For 2012, we expect to fund up to $124 million and $11 million for pension and OPEB, respectively.

In December, we were also able to early redeem $600 million of 6.95% Senior Notes due in June 2012 at Power.

In April 2011, PSEG, Power and PSE&G entered into new 5-year credit agreements resulting in an increase of $650 million in Power s credit capacity. As of December 31, 2011, our total credit capacity was $4.2 billion and we had over $800 million of cash on hand.

Disciplined Investment

We seek to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include upgrading critical energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. We also have several projects where we are investing to continue to improve our operational performance. Over the past few years, we have shifted our focus to investing at the utility. Our capital expenditure forecast includes over $6.8 billion in spending over the next three years, over 75% of which is at PSE&G.

During 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions for a total of $687 million. See Note 4. Discontinued Operations and Dispositions for further information.

We are continuing to pursue obtaining the necessary regulatory approvals for the Susquehanna-Roseland transmission project including approval from the National Park Service (NPS), which has resulted in a delay to the project implementation date. In October 2011, the NPS issued a Draft Environmental Impact Statement (EIS), which recommended a no action alternative that would require re-routing of the project around the affected federal park areas. The NPS has stated that it will select a final preferred route for the project in March 2012. We have submitted comments to the draft EIS and will continue to work with the NPS on mitigation for unavoidable impacts associated with the project. The estimated cost of construction is $750 million for this project. Our project estimate will be refined when we obtain additional information from the NPS regarding mitigation-related requirements as well as contractor bids.

In October 2010, PJM approved the North East Grid project, a 230 kV project running from Roseland to Hudson. This project has an expected in-service date of June 2015 with an estimated cost of construction of $895 million. We have also filed for BPU approval of the North-Central Reliability project, a 230 kV upgrade project located in the northern and central portions of New Jersey with an estimated cost of construction of approximately $390 million. The North-Central Reliability project has an expected in-service date of June 2014. Delays in the construction schedules of these projects could impact the timing of expected transmission revenues. The North East Grid project was approved in place of a previously approved 500 kV Branchburg-Roseland-Hudson project. On December 30, 2011, FERC granted incentive rates for the Northeast Grid project including recovery of 100% of Construction Work in Process (CWIP) in rate base and abandonment costs, along with a 25 basis point adder to ROE, with an effective date of January 1, 2012.

In April 2011, we filed a petition with FERC seeking incentive rates with an effective date of June 14, 2011 for five 230 kV transmission projects, including the North-Central Reliability project. In June 2011, FERC granted incentive rates for three of these 230 kV projects, with a total capital investment of approximately $1.0 billion, representing approximately 80% of our request. The incentive rates include recovery for CWIP and 100% recovery of prudently-incurred abandonment costs. See Item 1. Business, Federal Regulation, Transmission Regulation Transmission Expansion for further information.

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We have made additional investments in solar power in New Jersey. Under our solar loan program we have provided a total of $127 million in loans for 518 projects as of December 31, 2011, representing 38 MW to date. Under our Solar 4 All program we have made total program expenditures of approximately $361 million as of December 31, 2011. Approximately 25 MW of solar panels have been installed on distribution poles and another 33 MW representing 19 projects have been placed into service. Additional projects are in various stages of development. Our total anticipated expenditures to develop all approved 80 MW is approximately $451 million. The BPU is currently conducting a generic stakeholder proceeding, however, to examine whether utility rate-based solar programs should be modified, expanded or terminated in the future.

We made additional expenditures under our Capital Infrastructure Programs (CIP). As of December 31, 2011, total capital expenditures since inception of these programs were $702 million and $59 million for CIP I and CIP II, respectively. In July, the BPU approved CIP II which provides for approximately $273 million in accelerated capital investments in our electric and gas infrastructure through 2012.

We continued various construction activities at Power, including 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 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 are continuing our efforts to obtain an Early Site Permit for a new nuclear generating station to be located at the current site of Salem and Hope Creek stations. The NRC acceptance review is complete and agency evaluation is underway. There were no petitions filed for permission to intervene. The current NRC schedule would likely result in issuance of the Early Site Permit in 2014.

In January 2012, we acquired an additional 25 MW solar project at Energy Holdings, currently under construction in Arizona. Completion of this project is expected by the third quarter of 2012. All of the energy, capacity and environmental attributes generated by the project in the first 20 years are expected to be sold under a long-term power purchase agreement. The total investment for the project will be approximately $75 million.

As part of our ongoing efforts to focus on energy investments, in December 2011, we sold our investment in an office building in Denver, Colorado for approximately $215 million. Net proceeds from the sale were approximately $175 million. The sale resulted in an after-tax gain of $34 million.

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.

As a result of Dynegy s corporate reorganization in September 2011, Energy Holdings evaluated its likely recovery under the lease arrangements for the Roseton and Danskammer facilities leased to subsidiaries of Dynegy Holdings LLC (DH). Considering the overall value of the underlying assets subject to lease, Energy Holdings fully reserved its $264 million gross investment. This gross charge was reflected as a reduction to third quarter Operating Revenues and resulted in an after-tax charge of approximately $170 million. On November 7, 2011, DH including the lessee entities in our Danskammer and Roseton leveraged lease transactions (Dynegy leases), filed for relief under Chapter 11 of the Bankruptcy Code. DH filed a Restructuring Support Agreement (RSA) expected to become effective in August 2012 assuming confirmation of its plan of reorganization by the Bankruptcy Court.

On December 13, 2011, Energy Holdings and Dynegy reached a settlement agreement resolving disputes that had arisen between them with regard to DH s rejection of the Dynegy leases. The settlement agreement assigns to Dynegy our rights to certain future payments or distributions related to the Dynegy leases; it also resolves our claims under our Tax Indemnity Agreement with DH. The terms of the agreement include a cash payment of $7.5 million, which was received on January 4, 2012, and the allowance of a $110 million claim against DH payable through a mix of cash and notes upon final approval of the DH reorganization. The Court approved the settlement agreement and DH s rejection of the Dynegy leases with an effective date of December 30, 2011, triggering a write-off of the entire $264 million fully reserved gross lease receivable and the reclassification of $30 million of the deferred tax liability to current status.

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The ultimate amount recognized from our $110 million claim could change based upon the final outcome of Dynegy s RSA and the respective fair values of the securities received. See Note 8. Financing Receivables for further information.

RESULTS OF OPERATIONS

Earnings (Losses)	2011	2010	2009
	Years Ended December 31, Millions		
Power	$ 1,002	$ 1,136	$ 1,191
PSE&G (A)	521	359	325
Energy Holdings (B)	(134)	49	72
Other (C)	18	13	6
PSEG Income from Continuing Operations	**1,407**	**1,557**	**1,594**
Income (Loss) from Discontinued Operations, Including Gain on Disposal (D)	96	7	(2)
PSEG Net Income	**$ 1,503**	**$ 1,564**	**$ 1,592**

Earnings Per Share (Diluted)	2011	2010	2009
	Years Ended December 31,		
PSEG Income from Continuing Operations	**$ 2.77**	**$ 3.07**	**$ 3.14**
Income from Discontinued Operations, Including Gain on Disposal (D)	0.19	0.01	0.00
PSEG Net Income	**$ 2.96**	**$ 3.08**	**$ 3.14**

(A) PSE&G s results in 2010 include an after-tax charge of $72 million related to an agreement to refund previous Market Transition Charge (MTC) collections in the succeeding two years.

(B) Energy Holdings results include an after-tax charge of $170 million taken in 2011 related to the reserve for assets underlying a leveraged lease receivable. See Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables.

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

(D) 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) Fund and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Fund 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 related to the ARO. The combined after-tax impact on earnings of this activity for the years ended December 31, 2011, 2010 and 2009 is shown in the chart below along with the after-tax impacts of mark-to-market (MTM) activity:

	Millions, after tax		
Years Ended December 31,	**2011**	**2010**	**2009**
NDT Fund Income	$ 50	$ 46	$ 9
Non-Trading Mark-to-Market Gains (Losses)	$ 107	$ (1)	$ (11)

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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)	
	2011	2010	2009	2011 vs 2010		2010 vs 2009	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 11,079	$ 11,793	$ 12,035	$ (714)	(6)	$ (242)	(2)
Energy Costs	4,747	5,261	5,433	(514)	(10)	(172)	(3)
Operation and Maintenance	2,481	2,504	2,534	(23)	(1)	(30)	(1)
Depreciation and Amortization	976	955	819	21	2	136	17
Income from Equity Method Investments	4	4	17	0	0	(13)	(76)
Other Income and (Deductions)	135	158	85	(23)	(15)	73	86
Other-Than-Temporary Impairments	22	11	61	11	100	(50)	(82)
Interest Expense	475	472	521	3	1	(49)	(9)
Income Tax Expense	977	1,059	1,042	(82)	(8)	17	2
Income from Discontinued Operations, including Gain on Disposal, net of tax	96	7	(2)	89	N/A	9	N/A

The 2011 year-over-year decrease in our Income from Continuing Operations was driven by the following:

- $170 million after-tax charge taken in 2011 on leveraged leases related to Dynegy (see Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables),

- the absence of an after-tax charge of $72 million related to an agreement to refund previous Market Transition Charge (MTC) collections in the succeeding two years,

- lower average pricing and volumes for electricity sold under our BGS contracts,

- lower realized prices and/or lower sales volumes in the various power pools,

- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants, and

- the absence of realized gains recognized in 2010 due to restructuring of the investments in our Rabbi Trust.

The decreases were partially offset by:

- favorable amounts related to the MTM activity reported above,
- an increase in revenues from new wholesale contracts entered into in the first half of 2011, and
- lower Operation and Maintenance costs primarily due to lower pension and OPEB costs.

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 a result of customer migration,
- losses on certain wholesale electric energy supply contracts,
- the aforementioned $72 million after-tax charge recorded in June related to MTC,
- lower gas sales volumes and pricing due to milder winter weather and economic conditions, and
- lower gains on lease sales.

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The decreases were 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 Trust.

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, 2011	2010	2009	Increase/ (Decrease) 2011 vs 2010	Increase/ (Decrease) 2010 vs 2009
			Millions		
Income from Continuing Operations	$ 1,002	$ 1,136	$ 1,191	$ (134)	$ (55)
Income (Loss) from Discontinued Operations, net of tax	96	7	(2)	89	9
Net Income	$ 1,098	$ 1,143	$ 1,189	$ (45)	$ (46)

For the year ended December 31, 2011, the primary reasons for the decrease in Income from Continuing Operations were

- lower average pricing and lower volumes of electricity sold under our BGS contracts, as a result of customer migration,
- higher Operation and Maintenance expense related to planned outage work at certain of our fossil plants, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

The decreases were partially offset by

- favorable amounts related to the MTM activity,
- favorable results from our coal optimization efforts, and

- an increase from new wholesale contracts entered into in the first half of 2011.

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, and
- losses on certain wholesale electric energy supply contracts.

The decreases were 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.

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

Power	For the Years Ended December 31, 2011	2010	2009	Increase / (Decrease) 2011 vs 2010		Increase / (Decrease) 2010 vs 2009	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 6,143	$ 6,558	$ 6,772	$ (415)	(6)	$ (214)	(3)
Energy Costs	3,046	3,374	3,462	(328)	(10)	(88)	(3)
Operation and Maintenance	1,102	1,046	1,045	56	5	1	0
Depreciation and Amortization	224	175	184	49	28	(9)	(5)
Other Income (Deductions)	111	117	98	(6)	(5)	19	19
Other-Than-Temporary Impairments	20	9	60	11	122	(51)	(85)
Interest Expense	175	157	161	18	11	(4)	(2)
Income Tax Expense	685	778	767	(93)	(12)	11	1
Income (Loss) from Discontinued Operations	96	7	(2)	89	N/A	9	N/A

For the year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $415 million due to

Gas Supply Revenues decreased $290 million due primarily to

- a net decrease of $283 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2011 due to warmer average temperatures during the fourth quarter of 2011,

- a net decrease of $7 million due primarily to lower average gas prices partially offset by higher sales volumes to third party customers.

Generation Revenues decreased $143 million due primarily to

- a net decrease of $305 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts as a result of customer migration,

- a decrease of $70 million due primarily to lower capacity payments from the various power pools resulting from lower market prices, and

- a decrease of $8 million due to lower operating reserve revenue in 2011.

These were partially offset by

- an increase of $136 million from new wholesale load contracts in the PJM and New England (NE) regions commencing in January 2011 and April 2011, respectively, net of lower average realized prices in the NE region, and higher net revenues of $108 million due primarily to MTM gains on economic hedging activity of $228 million, partially offset by lower realized prices in the PJM and NY power pools and lower volumes of generation sold in the PJM and NE power pools of $120 million.

Trading Revenues increased $18 million due primarily to lower net losses in 2011 on certain electric energy supply contracts as well as the discontinuation of trading activities in the second quarter of 2011.

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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 $328 million due to

Gas costs decreased $282 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2011 due to warmer average temperatures during the fourth quarter of 2011.

Generation costs decreased by $46 million due primarily to $211 million of lower fuel costs, including $251 million of lower fossil fuel costs primarily reflecting the utilization of lower volumes of both coal and oil, favorable results from our coal optimization efforts, and lower natural gas prices, partially offset by higher MTM losses and higher nuclear fuel costs in 2011. The decrease was also attributable to $16 million of lower emission charges, including $10 million of lower impairment charges related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $153 million in higher energy purchases in 2011 in the PJM and NE power pools as the result of lower generation and the need to meet higher load contract demand in 2011 and $23 million of higher operating reserve obligations in the PJM region.

Operation and Maintenance increased $56 million due primarily to

a net increase of $47 million due largely to planned outage costs, including hot gas path inspection outage costs at our gas-fired BEC and Linden facilities as well as higher outage costs at our gas-fired Bergen facility, coal-fired Mercer facility in New Jersey and our coal-fired Keystone facility in Pennsylvania, partially offset by higher outage and repair costs at certain of our other fossil plants in 2010,

$20 million of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services for our combined cycle Bethlehem Energy (BEC) facility in New York and Linden and Bergen facilities in New Jersey, and

a net increase of $3 million due to refurbishment projects at our Salem nuclear facilities,

partially offset by a decrease of $13 million due to a decrease in pension and OPEB costs tempered by higher labor costs and incentive awards.

Depreciation and Amortization increased $49 million due primarily to

a $37 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and

a $12 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net decrease of $6 million was due primarily to

a $17 million premium paid on the early extinguishment of 6.95% Senior Notes due in June 2012, and the absence of $7 million of gains realized in 2010 from restructuring the Rabbi Trust,

partially offset by higher net realized gains of $19 million on our NDT Fund.

Other-Than-Temporary Impairments increased $11 million due primarily to higher impairments on the NDT Fund in 2011.

Interest Expense increased $18 million due primarily to

Higher interest expense of $49 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson fossil stations for which we had been allowed to capitalize interest costs in 2010 while such projects were under construction,

partially offset by lower interest expense of $30 million due primarily to the redemption of $606 million of 7.75% Senior Notes in early April 2011 and lower debt issuance costs of $3 million.

Income Tax Expense decreased $93 million in 2011 due primarily to lower pre-tax income.

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Income (Loss) from Discontinued Operations

In 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million at an after-tax gain of $54 million. In July, we completed the sale of the second plant for proceeds of $335 million at an after-tax gain of $25 million. The results of operations for both plants for 2011 and 2010, including the gains in 2011 on the sales of the plants, are included in this category. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations and Dispositions for additional information.

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

- increased net revenues of $161 million due to higher average realized prices offset by lower volumes of generation sold in the PJM power pool,
- an increase of $166 million from new wholesale load contracts in PJM commencing in January 2010, and
- an increase of $20 million in capacity payments largely due to changes in PJM s capacity market,
- partially offset by a net decrease of $184 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of customer migration.

Operating Expenses

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 $206 million due primarily to $208 million of higher fossil fuel costs, primarily reflecting the utilization of higher volumes of both coal and natural gas, $22 million of higher net energy purchases due to higher purchases in the PJM region

to meet higher load contract demand in 2010 offset by lower energy purchases in the NE region driven by the expiration of certain contracts in 2010, $15 million of higher nuclear fuel costs as a result of higher prices, and an $18 million impairment charge in 2010 related to forecasted excess SO_2 emissions allowances. These increases were partially offset by $40 million of lower congestion charges and $28 million of lower purchases of firm transmission rights in PJM 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. This was 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

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- 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 Fund and other miscellaneous adjustments,
- partially offset by a decrease of $18 million due to lower pre-tax income.

Income (Loss) from Discontinued Operations

As discussed above, we sold our two Texas plants in March 2011 and July 2011, respectively. The results of operations for both plants for 2010 and 2009 are included in this category. 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, 2011	2010	2009	Increase/ (Decrease) 2011 vs 2010	Increase/ (Decrease) 2010 vs 2009
			Millions		
Income from Continuing Operations	$ 521	$ 359	$ 325	$ 162	$ 34
Net Income	$ 521	$ 359	$ 325	$ 162	$ 34

For the year ended December 31, 2011, the primary reasons for the increase in Income from Continuing Operations were

the absence of a $72 million after-tax charge recorded in June 2010 related to the refund of previous MTC collections,

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higher annualized base rates for electric and gas delivery as well as transmission, and

lower Operation and Maintenance expense, largely due to lower pension and OPEB costs.

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.

The increases were partially offset by

the $72 million after-tax MTC charge in 2010, and

lower gas sales volumes due to milder winter weather.

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

PSE&G	For the Years Ended December 31, 2011	2010	2009	Increase/ (Decrease) 2011 vs 2010		Increase/ (Decrease) 2010 vs 2009	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 7,326	$ 7,869	$ 8,243	$ (543)	(7)	$ (374)	(5)
Energy Costs	3,951	4,655	5,170	(704)	(15)	(515)	(10)
Operation and Maintenance	1,372	1,442	1,474	(70)	(5)	(32)	(2)
Depreciation and Amortization	719	750	608	(31)	(4)	142	23
Other Income and (Deductions)	21	23	5	(2)	(9)	18	N/A
Other-Than-Temporary Impairments	1	0	0	1	N/A	0	0
Interest Expense	310	318	312	(8)	(3)	6	2
Income Tax Expense	340	232	226	108	47	6	3

For the year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $543 million due primarily to

Commodity Revenue decreased $704 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 $397 million due primarily to $466 million in lower BGS revenues, partially offset by $69 million in higher revenues from the sale of Non-Utility (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to higher prices. BGS sales decreased 16% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales decreased only 2%.

Gas revenues decreased $307 million due to lower BGSS prices of $259 million and lower BGSS volumes of $48 million. The average price of gas was 3% lower in 2011 than in 2010.

Delivery Revenues increased $74 million due primarily to an increase in prices for electric and gas distribution and transmission.

Transmission revenues were $42 million higher due primarily to net rate increases.

Gas distribution revenues increased $32 million due primarily to higher Weather Normalization Clause revenue of $19 million and the impact of base rate increases of $17 million, partially offset by lower capital stimulus revenue of $5 million. The lower stimulus revenue is offset by a deferral in O&M.

Electric distribution revenues were flat due primarily to the impact of base rate increases of $17 million and higher stimulus revenue of $1 million, offset by lower sales volumes of $18 million. The lower stimulus revenue is offset by a deferral in O&M.

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Clause Revenues increased $73 million due primarily to the absence of $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years and higher Societal Benefit Charges (SBC) and Margin Adjustment Clause (MAC) of $49 million, partially offset by lower STC revenues of $98 million. The changes in Securitization Transition Charge (STC), SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Energy Costs decreased $704 million. This is entirely offset by Commodity Revenue. Details are as follows:

- Electric costs decreased $397 million due to $405 million or 14% in lower BGS and NUG volumes due to customer migration to TPS and $75 million of lower BGS and NUG prices, partially offset by $83 million for increased deferred cost recovery.

- Gas costs decreased $307 million due to $259 million or 16% in lower prices and $48 million or 3% in lower sales volumes due primarily to weather.

Operation and Maintenance decreased $70 million due primarily to

- a $71 million decrease in pension and other postretirement benefits (OPEB) expenses,

- $20 million of lower net deferred expenses associated with SBC, RGGI and Stimulus clauses, and

- the absence of $15 million in expenses relating to 2010 rate case disallowances.

These were partially offset by

- a $9 million increase in storm restoration work,

- a $6 million increase in costs relating to tree trimming,

- a $3 million increase in bad debt expense, and

- a $3 million increase in incentive payments.

Depreciation and Amortization decreased $31 million due primarily to

- a decrease of $63 million for amortization of Regulatory Assets, partially offset by an increase of $28 million for additional plant in service, and an increase of $3 million in net other charges.

Other Income and (Deductions) experienced no material change.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $8 million due primarily to lower average debt balances.

Income Tax Expense increased $108 million due primarily to higher pre-tax income.

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 NUG energy and collections of NGCs due primarily to higher prices. BGS sales were down 9% due primarily to large customer migration to TPS; in contrast delivery sales were up 5% due to warmer weather.

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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 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.

These were partially offset by

- a $14 million write-off of deferred costs associated with a 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.

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.

Energy Holdings

	For the Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2011	2010	2009	2011 vs 2010	2010 vs 2009
	Millions				
Income (Loss) from Continuing Operations	$ (134)	$ 49	$ 72	$ (183)	$ (23)
Net Income (Loss)	$ (134)	$ 49	$ 72	$ (183)	$ (23)

For the year ended December 31, 2011, the primary reason for the decrease in Income from Continuing Operations was

- the $170 million after-tax charge on leveraged leases related to Dynegy (see Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables).

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.

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 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. PSE&G maintains back-up facilities in an amount sufficient to cover 100% of commercial paper outstanding. PSE&G s dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain 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 PSEG Services Corporation 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 multi-year syndicated credit facilities totaling $977 million. These facilities are available to back-stop PSEG s commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to Power for the issuance of letters of credit. PSEG s credit facilities and the 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.

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Power s sources of external liquidity include $2.6 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 maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2011, our operating cash flow increased by $1,393 million. For the year ended December 31, 2010, our operating cash flow increased by $309 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power s operating cash flow increased $246 million from $1,566 million to $1,812 million for the year ended December 31, 2011, as compared to 2010, primarily resulting from

- an increase of $368 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data Note 20. Income Taxes for additional information), and
- a $302 million increase from net collection of counterparty receivables.

These were partially offset by:

- a $171 million increase in net payment of counterparty payables,
- a $161 million net increase in spending on fuel inventories, and
- lower earnings.

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.

PSE&G

PSE&G s operating cash flow increased $765 million from $1,011 million to $1,776 million for the year ended December 31, 2011 as compared to 2010, due primarily to higher earnings combined with

an increase of $587 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data Note 20. Income Taxes for additional information), and

an increase of $273 million due to higher collections of customer receivables,

partially offset by a decrease of $108 million in net other working capital.

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,

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a $102 million net increase in other working capital including increased customer advances, increased collections for TPS 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.

Energy Holdings

Energy Holdings operating cash flow increased $341 million for the year ended December 31, 2011, as compared to 2010, primarily due to lower tax payments in 2011 related to the absence of lease sale activity in 2011.

Energy Holdings operating cash flow increased 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 and a $140 million additional tax deposit made with the IRS in June 2009.

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, 2011 were as follows:

	As of December 31, 2011		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
		Millions	
PSEG	$ 977	$ 12	$ 965
Power	2,625	175	2,450
PSE&G	600	0	600
Total	**$ 4,202**	**$ 187**	**$ 4,015**

As of December 31, 2011, our total credit facility capacity was in excess of our anticipated maximum liquidity requirements through 2012. 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 $66 million of 5.00% Pollution Control Notes maturing in March 2012. PSE&G has $300 million of 5.13% Medium Term Notes maturing in September 2012.

For a discussion of our long-term debt transactions during 2011 and into 2012, 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 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.

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In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2011, PSE&G s Mortgage coverage ratio was 4.8 to 1 and the Mortgage would permit up to approximately $2.7 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 agreements contain 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 agreements, 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 would not be 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.

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	**2011**	**2010**	**2009**
Per Share	$ 1.37	$ 1.37	$ 1.33
in Millions	$ 693	$ 693	$ 673

On February 21, 2012, our Board of Directors approved a $0.3550 per share common stock dividend for the first quarter of 2012. This reflects an indicated annual dividend rate of $1.42 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 April 2011, S&P published an updated credit opinion which left the ratings for PSEG, Power and PSE&G unchanged and improved their outlooks to positive from stable. In May 2011, Moody s affirmed its ratings for PSEG, Power and PSE&G. PSE&G s outlook was improved to positive from stable while the outlooks at PSEG and Power remain at stable. In August 2011, Fitch affirmed its ratings for PSEG, Power and PSE&G and kept all outlooks at stable. In October 2011, S&P published updated research on Power and PSE&G, which left their respective ratings and outlooks unchanged. In December 2011, S&P published updated research on PSEG, which left its ratings and outlook unchanged.

	Moody s(A)	S&P(B)	Fitch(C)
PSEG:			
Outlook	**Stable**	**Positive**	**Stable**
Commercial Paper	P2	A2	F2
Power:			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB	BBB+
PSE&G:			
Outlook	**Positive**	**Positive**	**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, 2011, we had Other Comprehensive Loss of $181 million on a consolidated basis. Other Comprehensive Loss was due primarily to $80 million of unrealized losses on derivative contracts accounted for as hedges, a $62 million increase in our consolidated liability for pension and postretirement benefits and $39 million of net unrealized losses 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. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2012	2013	2014
Power:		Millions	
Baseline Maintenance	$ 330	$ 185	$ 175
Environmental/Regulatory	70	95	80
Fossil Growth Opportunities	65	0	0
Nuclear Expansion	75	120	120
Total Power	**$ 540**	**$ 400**	**$ 375**
PSE&G:			
Transmission			
Reliability Enhancements	$ 870	$ 1,165	$ 1,015
Facility Replacement	115	140	175
Support Facilities	10	15	10
Distribution			
Reliability Enhancements	200	75	80
Facility Replacement	265	135	135
Support Facilities	45	40	60
New Business	120	130	130
Environmental/Regulatory	30	30	30
Renewables/EMP	250	60	25
Total PSE&G	**$ 1,905**	**$ 1,790**	**$ 1,660**
Non-Utility Renewables	75	0	0
Other	45	40	30
Total PSEG	**$ 2,565**	**$ 2,230**	**$ 2,065**

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 enhance 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.

In 2011, Power made $563 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $194 million for nuclear fuel, primarily related to various projects at Fossil and 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:

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.

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).

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 2011, PSE&G made $1,359 million of capital expenditures, including $1,302 million of investment in plant, primarily for transmission and distribution system reliability and $57 million in solar loan investments. This does not include expenditures for certain energy efficiency and renewable programs of $46 million or cost of removal, net of salvage, of $62 million, which are included in operating cash flows.

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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. For additional information, see Item 8. Financial Statements and Supplementary Data Note 14. Schedule of Consolidated Debt. The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data Note 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					
Long-Term Recourse Debt Maturities					
Power	$ 2,767	$ 66	$ 594	$ 853	$ 1,254
PSE&G	4,277	300	1,225	471	2,281
Transition Funding (PSE&G)	895	205	439	251	0
Transition Funding II (PSE&G)	44	11	25	8	0
Long-Term Non-Recourse Project Financing					
Energy Holdings (A)	45	1	2	24	18
Interest on Recourse Debt					
Power	1,458	141	262	222	833
PSE&G	2,999	216	357	273	2,153
Transition Funding (PSE&G)	136	56	69	11	0
Transition Funding II (PSE&G)	4	2	2	0	0
Interest on Non-Recourse Project Financing					
Energy Holdings (A)	14	2	4	4	4
Capital Lease Obligations					
PSEG	27	7	14	6	0
Power	6	2	3	1	0
Operating Leases					
Power	8	0	1	2	5
PSE&G	50	6	9	5	30
Energy Holdings	9	1	1	0	7
Energy-Related Purchase Commitments					
Power	2,694	815	868	795	216
Total Contractual Cash Obligations	**$ 15,433**	**$ 1,831**	**$ 3,875**	**$ 2,926**	**$ 6,801**
Commercial Commitments					
Standby Letters of Credit					
Power	$ 232	$ 187	$ 45	$ 0	$ 0
Energy Holdings	1	1	0	0	0
Guarantees and Equity Commitments					
Energy Holdings	72	72	0	0	0
Total Commercial Commitments	**$ 305**	**$ 260**	**$ 45**	**$ 0**	**$ 0**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 35	$ 35	$ 0	$ 0	$ 0
Power	64	64	0	0	0
PSE&G	27	27	0	0	0
Energy Holdings	453	453	0	0	0

(A) The Energy Holdings non-recourse debt contractual cash obligations exclude any related principal and interest associated with the Dynegy related debt. See Item 8. Financial Statements and Supplementary Data Note 14. Schedule of Consolidated Debt for further discussion.

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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 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. One of the companies in which we invest that is accounted for under the equity method has an aggregate $47 million of long-term debt on its Consolidated Balance Sheet. Our pro-rata share of such debt is $24 million. This debt is non-recourse to us. We are generally not required to support the debt service obligations of this company. 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, secures 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 operations. 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 this event occur, 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	**2011**	**2010**	**2009**
Discount Rate	5.00%	5.51%	5.91%
Rate of Return on Plan Assets	8.50%	8.50%	8.75%

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 $119 million, net of amounts capitalized, and contributions of up to $124 million in 2012.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 5.00% discount rate for 2012, a 5.25% discount rate for 2013 and a 5.50% discount rate for 2014 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 12/31/2011	
		Impact on Pension Benefit Obligation	**Increase to Pension Expense in 2012**
Assumption	**Change**	Millions	
Discount Rate	-1%	$ 622	$ 61
Rate of Return on Plan Assets	-1%	$ 0	$ 38

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

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, 2011 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.

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Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many non-trading contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

Assumptions and Approach Used**:** In general, the fair value of our 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.

For a small number of contracts where quoted market prices are not available, 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 the fair value to record in the financial statements.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, 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 hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in 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 the effective portion of derivative instruments designated as cash flow hedges, are reported in Accumulated Other Comprehensive Income (Loss), net of tax, 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. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss).

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 either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

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

Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data Note 7. Long-Term Investments, and Note 8. Financing Receivables.

Assumptions and Approach Used: Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease;
- related prices of fuel for the plants;
- dispatch rates for the plants;
- future capital expenditures required to maintain the plants;
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

Effect if Different Assumptions Used: A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market s view of long-term power prices, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $170 million.

NDT Fund

Our NDT Funds is comprised of both debt and equity securities. The assets in the NDT Fund 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.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power s nuclear facilities comprised 92% of Power s total AROs as of December 31, 2011. 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 $104 million increase in the Nuclear ARO as of December 31, 2011. A 1% increase in the inflation rate used at December 31, 2009 would result in a $188 million increase in the Nuclear ARO as of December 31, 2011. 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 $76 million at December 31, 2011. These changes would not have a material impact on net income in 2012.

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.

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.

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. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

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As of December 31, 2011, there was no trading VaR since we discontinued trading activities in the second quarter of 2011. As of December 31, 2010, trading VaR was $1 million.

For the Year Ended December 31, 2011	Trading VaR	Non-Trading MTM VaR
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 0	$ 16
Average for the Period	$ 0	$ 9
High	$ 2	$ 19
Low	$ 0	$ 4
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 0	$ 25
Average for the Period	$ 1	$ 14
High	$ 3	$ 30
Low	$ 0	$ 7

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, 2011, 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 $200 million decrease in the fair value of debt, including a $72 million decrease at Power and a $127 million decrease at PSE&G.

Debt and Equity Securities

We have $4.0 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 Fund is comprised of both fixed income and equity securities totaling $1.3 billion as of December 31, 2011. As of December 31, 2011, the portfolio includes $685 million of equity securities and $640 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2011, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $69 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 Fund currently has a duration of 4.95 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, 2011, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $32 million.

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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 $165 million, which is net of deferred taxes of $716 million, as of December 31, 2011. 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 temporary 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. FINANCIALSTATEMENTS 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, 2011 and 2010, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey
February 27, 2012

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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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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 27, 2012

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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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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 27, 2012

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31, 2011	2010	2009
OPERATING REVENUES	$ 11,079	$ 11,793	$ 12,035
OPERATING EXPENSES			
Energy Costs	4,747	5,261	5,433
Operation and Maintenance	2,481	2,504	2,534
Depreciation and Amortization	976	955	819
Taxes Other Than Income Taxes	133	136	133
Total Operating Expenses	8,337	8,856	8,919
OPERATING INCOME	2,742	2,937	3,116
Income from Equity Method Investments	4	4	17
Other Income	220	221	246
Other Deductions	(85)	(63)	(161)
Other-Than-Temporary Impairments	(22)	(11)	(61)
Interest Expense	(475)	(472)	(521)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,384	2,616	2,636
Income Tax (Expense) Benefit	(977)	(1,059)	(1,042)
INCOME FROM CONTINUING OPERATIONS	1,407	1,557	1,594
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(51), $(8) and $(2) for the years ended 2011, 2010 and 2009, respectively	96	7	(2)
NET INCOME	$ 1,503	$ 1,564	$ 1,592
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,949	505,985	505,986
DILUTED	506,982	507,045	507,064
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$ 2.78	$ 3.08	$ 3.15
NET INCOME	$ 2.97	$ 3.09	$ 3.15
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$ 2.77	$ 3.07	$ 3.14
NET INCOME	$ 2.96	$ 3.08	$ 3.14
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 1.37	$ 1.37	$ 1.33

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 834	$ 280
Accounts Receivable, net of allowances of $56 and $68 in 2011 and 2010, respectively	967	1,387
Tax Receivable	16	689
Unbilled Revenues	289	400
Fuel	685	666
Materials and Supplies, net	367	359
Prepayments	308	204
Derivative Contracts	156	182
Assets of Discontinued Operations	0	564
Deferred Income Taxes	0	43
Regulatory Assets	167	155
Other	122	122
Total Current Assets	3,911	5,051
PROPERTY, PLANT AND EQUIPMENT	25,080	23,272
Less: Accumulated Depreciation and Amortization	(7,231)	(6,882)
Net Property, Plant and Equipment	17,849	16,390
NONCURRENT ASSETS		
Regulatory Assets	3,805	3,736
Regulatory Assets of Variable Interest Entities (VIEs)	925	1,128
Long-Term Investments	1,303	1,623
Nuclear Decommissioning Trust (NDT) Funds	1,349	1,363
Other Special Funds	172	160
Goodwill	16	16
Other Intangibles	131	136
Derivative Contracts	106	79
Restricted Cash of VIEs	22	21
Other	232	206
Total Noncurrent Assets	8,061	8,468
TOTAL ASSETS	$ 29,821	$ 29,909

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year (includes $50 at fair value as of December 31, 2011)	$ 417	$ 915
Securitization Debt of VIEs Due Within One Year	216	206
Commercial Paper and Loans	0	64
Accounts Payable	1,184	1,176
Derivative Contracts	131	103
Accrued Interest	97	108
Accrued Taxes	30	49
Deferred Income Taxes	170	0
Clean Energy Program	214	195
Obligation to Return Cash Collateral	107	104
Regulatory Liabilities	100	174
Liabilities of Discontinued Operations	0	72
Other	291	319
Total Current Liabilities	2,957	3,485
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,458	5,129
Regulatory Liabilities	228	285
Regulatory Liabilities of VIEs	9	8
Asset Retirement Obligations	489	461
Other Postretirement Benefit (OPEB) Costs	1,127	967
Accrued Pension Costs	734	788
Clean Energy Program	39	235
Environmental Costs	643	669
Derivative Contracts	26	22
Long-Term Accrued Taxes	292	248
Other	86	152
Total Noncurrent Liabilities	9,131	8,964
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,694	6,834
Securitization Debt of VIEs	723	939
Project Level, Non-Recourse Debt	44	46
Total Long-Term Debt	7,461	7,819
STOCKHOLDERS EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2011 and 2010 533,556,660 shares	4,823	4,807
Treasury Stock, at cost, 2011 27,611,374 shares; 2010 27,582,437 shares	(601)	(593)
Retained Earnings	6,385	5,575

Accumulated Other Comprehensive Loss	(337)	(156)
Total Common Stockholders Equity	10,270	9,633
Noncontrolling Interest	2	8
Total Stockholders Equity	10,272	9,641
Total Capitalization	17,733	17,460
TOTAL LIABILITIES AND CAPITALIZATION	$ 29,821	$ 29,909

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,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,503	$ 1,564	$ 1,592
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	(122)	0	0
Depreciation and Amortization	982	974	838
Amortization of Nuclear Fuel	153	136	121
Provision for Deferred Income Taxes (Other than Leases) and ITC	811	1,106	326
Non-Cash Employee Benefit Plan Costs	175	315	347
Lease Transaction Reserves, net of tax	170	0	(29)
Net (Gain) Loss on Lease Investments	(55)	(56)	(167)
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(55)	(336)	(678)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(165)	50	25
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	43	(36)	(32)
Over (Under) Recovery of Societal Benefits Charge (SBC)	(96)	(123)	4
Market Transition Charge Refund	(61)	84	0
Cost of Removal	(62)	(58)	(54)
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(117)	(106)	(50)
Net Change in Tax Receivable	673	(689)	0
Net Change in Certain Current Assets and Liabilities	247	(221)	221
Employee Benefit Plan Funding and Related Payments	(508)	(508)	(446)
Other	41	68	(163)
Net Cash Provided By (Used In) Operating Activities	3,557	2,164	1,855
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,083)	(2,160)	(1,794)
Proceeds from Sale of Discontinued Operations	687	0	0
Proceeds from the Sale of Capital Leases and Investments	179	496	880
Proceeds from Sales of Available-for-Sale Securities	1,355	1,116	1,769
Investments in Available-for-Sale Securities	(1,386)	(1,140)	(1,798)
Restricted Funds	0	(2)	116
Other	(21)	21	35
Net Cash Provided By (Used In) Investing Activities	(1,269)	(1,669)	(792)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	(64)	(466)	511
Issuance of Long-Term Debt	794	1,728	459
Redemption of Long-Term Debt	(1,514)	(775)	(820)
Repayment of Non-Recourse Debt	(1)	(32)	(286)
Redemption of Securitization Debt	(206)	(197)	(187)
Premium Paid on Debt Exchange/Redemption	(17)	(18)	(36)
Cash Dividends Paid on Common Stock	(693)	(693)	(673)
Redemption of Preferred Securities	0	(80)	0
Other	(33)	(32)	(2)

Net Cash Provided By (Used In) Financing Activities	(1,734)	(565)	(1,034)
Net Increase (Decrease) in Cash and Cash Equivalents	554	(70)	29
Cash and Cash Equivalents at Beginning of Period	280	350	321
Cash and Cash Equivalents at End of Period	$ 834	$ 280	$ 350
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (219)	$ 1,070	$ 1,364
Interest Paid, Net of Amounts Capitalized	$ 479	$ 444	$ 500

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Millions

	Common Stockholders Equity							
	Common Stock		Treasury Stock		Retained	Accumulated Other Comprehensive	Noncontrolling	
	Shs.	Amount	Shs.	Amount	Earnings	Income (Loss)	Interest	Total
Balance as of January 1, 2009	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 of $93	0	0	0	0	0	94	0	94
Change in Fair Value of Derivative Instruments, net of tax of $245	0	0	0	0	0	356	0	356
Reclassification Adjustments for Net Amounts included in Net Income, net of tax of $(240)	0	0	0	0	0	(348)	0	(348)
Pension/OPEB adjustment, net of tax of $(25)	0	0	0	0	0	(29)	0	(29)
Other Comprehensive Income								73
Comprehensive Income								1,665
Adoption of Accounting Guidance for Non-Credit Losses	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 of $12	0	0	0	0	0	6	0	6
Change in Fair Value of Derivative Instruments, net of tax of $42	0	0	0	0	0	60	0	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax of $(90)	0	0	0	0	0	(129)	0	(129)
Pension/OPEB adjustment, net of tax of $18	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
Net Income	0	0	0	0	1,503	0	0	1,503
Other Comprehensive Income (Loss), net of tax:								
Available-for-Sale Securities, net of tax of $(43)	0	0	0	0	0	(39)	0	(39)
Change in Fair Value of Derivative Instruments, net of tax of $33	0	0	0	0	0	47	0	47
Reclassification Adjustments for Net Amounts included in Net Income, net of tax of $(87)	0	0	0	0	0	(127)	0	(127)

Pension/OPEB adjustment, net of tax of $(44)	0	0	0	0	0	(62)	0	(62)
Other Comprehensive Income (Loss)								(181)
Comprehensive Income								1,322
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	(6)	(6)
Other	0	16	0	(8)	0	0	0	8
Balance as of December 31, 2011	534	$ 4,823	(28)	$ (601)	$ 6,385	$ (337)	$ 2	$ 10,272

See Notes to Consolidated Financial Statements.

PSEG POWER LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

	For The Years Ended December 31,		
	2011	**2010**	**2009**
OPERATING REVENUES	$ 6,143	$ 6,558	$ 6,772
OPERATING EXPENSES			
Energy Costs	3,046	3,374	3,462
Operation and Maintenance	1,102	1,046	1,045
Depreciation and Amortization	224	175	184
Total Operating Expenses	4,372	4,595	4,691
OPERATING INCOME	1,771	1,963	2,081
Other Income	190	170	233
Other Deductions	(79)	(53)	(135)
Other-Than-Temporary Impairments	(20)	(9)	(60)
Interest Expense	(175)	(157)	(161)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,687	1,914	1,958
Income Tax (Expense) Benefit	(685)	(778)	(767)
INCOME FROM CONTINUING OPERATIONS	1,002	1,136	1,191
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(51), $(8) and $(2) for the years ended 2011, 2010 and 2009, respectively	96	7	(2)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 1,098	$ 1,143	$ 1,189

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

PSEG POWER LLC

CONSOLIDATED BALANCE SHEETS

Millions

	December 31, 2011	2010
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12	$ 11
Accounts Receivable	267	511
Accounts Receivable Affiliated Companies, net	381	782
Short-Term Loan to Affiliate	907	398
Fuel	685	666
Materials and Supplies, net	272	269
Derivative Contracts	139	163
Prepayments	24	80
Assets of Discontinued Operations	0	564
Total Current Assets	2,687	3,444
PROPERTY, PLANT AND EQUIPMENT	9,191	8,643
Less: Accumulated Depreciation and Amortization	(2,460)	(2,301)
Net Property, Plant and Equipment	6,731	6,342
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Funds	1,349	1,363
Goodwill	16	16
Other Intangibles	131	130
Other Special Funds	33	32
Derivative Contracts	55	42
Long-Term Accrued Taxes	0	16
Other	85	67
Total Noncurrent Assets	1,669	1,666
TOTAL ASSETS	$ 11,087	$ 11,452

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, 2011	December 31, 2010
LIABILITIES AND MEMBER S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 66	$ 650
Accounts Payable	541	643
Derivative Contracts	124	91
Deferred Income Taxes	53	64
Accrued Interest	32	40
Liabilities of Discontinued Operations	0	72
Other	86	91
Total Current Liabilities	902	1,651
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,266	1,146
Asset Retirement Obligations	259	242
Other Postretirement Benefit (OPEB) Costs	180	151
Derivative Contracts	24	22
Accrued Pension Costs	236	253
Long-Term Accrued Taxes	8	0
Other	83	155
Total Noncurrent Liabilities	2,056	1,969
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT		
Total Long-Term Debt	2,685	2,805
MEMBER S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,678	4,080
Accumulated Other Comprehensive Loss	(276)	(95)
Total Member s Equity	5,444	5,027
TOTAL LIABILITIES AND MEMBER S EQUITY	$ 11,087	$ 11,452

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,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,098	$ 1,143	$ 1,189
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	(122)	0	0
Depreciation and Amortization	231	194	203
Amortization of Nuclear Fuel	153	136	121
Provision for Deferred Income Taxes and ITC	231	650	133
Interest Accretion on Asset Retirement Obligation	18	18	27
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(165)	50	25
Loss on Early Extinguishment of Debt	17	0	0
Non-Cash Employee Benefit Plan Costs	41	71	76
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(117)	(106)	(50)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	(26)	135	97
Margin Deposit	49	(91)	(31)
Accounts Receivable	197	(105)	109
Accounts Payable	(154)	17	(115)
Accounts Receivable/Payable-Affiliated Companies, net	459	(386)	75
Other Current Assets and Liabilities	30	(66)	(27)
Employee Benefit Plan Funding and Related Payments	(129)	(132)	(114)
Other	1	38	(60)
Net Cash Provided By (Used In) Operating Activities	1,812	1,566	1,658
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(757)	(825)	(869)
Settlement of Spent Nuclear Fuel Claim	0	16	47
Proceeds from Sale of Discontinued Operations	687	0	0
Proceeds from Sales of Available-for-Sale Securities	1,355	989	1,769
Investments in Available-for-Sale Securities	(1,380)	(1,013)	(1,798)
Short-Term Loan Affiliated Company, net	(509)	(398)	55
Restricted Funds	0	2	115
Other	26	24	29
Net Cash Provided By (Used In) Investing Activities	(578)	(1,205)	(652)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	544	594	209
Contributed Capital	0	0	230
Cash Dividend Paid	(500)	(549)	(940)
Redemption of Long-Term Debt	(1,250)	(248)	(294)
Redemption of Non-Recourse Long-Term Debt	0	0	(280)
Short-Term Loan Affiliated Company, net	0	(194)	194

Cash Payment on Debt Redemption/Exchange	(17)	(13)	(101)
Other	(10)	(4)	0
Net Cash Provided By (Used In) Financing Activities	(1,233)	(414)	(982)
Net Increase (Decrease) in Cash and Cash Equivalents	1	(53)	24
Cash and Cash Equivalents at Beginning of Period	11	64	40
Cash and Cash Equivalents at End of Period	$ 12	$ 11	$ 64
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 171	$ 539	$ 584
Interest Paid, Net of Amounts Capitalized	$ 176	$ 151	$ 160

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
Balance as of January 1, 2009	$ 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 of $89	0	0	0	88	88
Change in Fair Value of Derivative Instruments, net of tax of $247	0	0	0	358	358
Reclassification Adjustments for Net Amount included in Net Income, net of tax of $(242)	0	0	0	(350)	(350)
Pension/OPEB adjustment, net of tax of $(21)	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 of $17	0	0	0	15	15
Change in Fair Value of Derivative Instruments, net of tax of $42	0	0	0	60	60
Reclassification Adjustments for Net Amount included in Net Income, net of tax of $(90)	0	0	0	(129)	(129)
Pension/OPEB adjustment, net of tax of $15	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
Net Income	0	0	1,098	0	1,098
Other Comprehensive Income (Loss), net of tax:					
Available-for-Sale Securities, net of tax of $(45)	0	0	0	(42)	(42)
	0	0	0	47	47

Change in Fair Value of Derivative Instruments, net of tax of $33				
Reclassification Adjustments for Net Amount included in Net Income, net of tax of $(87)	0	0	0	(127)