PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 25, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

100 F ST., N.E.

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010,

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE**

SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza T25	22-3663480

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

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

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

Registrant	**Title of Each Class**	**Name of Each Exchange On Which Registered**
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange
Public Service Electric and Gas Company	**First and Refunding Mortgage Bonds**	
	9 1/4% Series CC, due 2021	New York Stock Exchange
	6 3/4% Series VV, due 2016	
	8%, due 2037	
	5%, due 2037	

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)

Table of Contents

(Cover continued from previous page)

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

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

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

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

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

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

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

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

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

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2010 was $15,837,199,627 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated s sole class of Common Stock as of January 31, 2011 was 506,039,601.

As of January 31, 2011, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2011 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 10, 2011, as specified herein.

TABLE OF CONTENTS

		Page
FORWARD-LOOKING STATEMENTS		ii
FILING FORMAT AND GLOSSARY		1
WHERE TO FIND MORE INFORMATION		1
PART I		
Item 1.	Business	1
	Regulatory Issues	17
	Environmental Matters	30
	Segment Information	35
Item 1A.	Risk Factors	35
Item 1B.	Unresolved Staff Comments	44
Item 2.	Properties	44
Item 3.	Legal Proceedings	47
PART II		
Item 5.	Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	50
Item 6.	Selected Financial Data	52
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	53
	Overview of 2010 and Future Outlook	53
	Results of Operations	58
	Liquidity and Capital Resources	70
	Capital Requirements	75
	Off-Balance Sheet Arrangements	78
	Critical Accounting Estimates	78
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	83
Item 8.	Financial Statements and Supplementary Data	85
	Report of Independent Registered Public Accounting Firm	86
	Consolidated Financial Statements	89
	Notes to Consolidated Financial Statements	
	Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies	104
	Note 2. Recent Accounting Standards	108
	Note 3. Variable Interest Entities	109
	Note 4. Discontinued Operations and Dispositions	110
	Note 5. Property, Plant and Equipment and Jointly-Owned Facilities	112
	Note 6. Regulatory Assets and Liabilities	114
	Note 7. Long-Term Investments	119
	Note 8. Financing Receivables	120
	Note 9. Available-for-Sale Securities	121
	Note 10. Goodwill and Other Intangibles	125
	Note 11. Asset Retirement Obligations (AROs)	126
	Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans	126
	Note 13. Commitments and Contingent Liabilities	133
	Note 14. Schedule of Consolidated Debt	146
	Note 15. Schedule of Consolidated Capital Stock and Other Securities	153
	Note 16. Financial Risk Management Activities	154
	Note 17. Fair Value Measurements	161
	Note 18. Stock Based Compensation	167
	Note 19. Other Income and Deductions	171
	Note 20. Income Taxes	172
	Note 21. Earnings Per Share (EPS) and Dividends	181
	Note 22. Financial Information by Business Segment	182
	Note 23. Related-Party Transactions	184
	Note 24. Selected Quarterly Data (Unaudited)	187
	Note 25. Guarantees of Debt	188
Item 9.	Changes In and Disagreements With Accountants on Accounting and Financial Disclosure	192
Item 9A.	Controls and Procedures	192
Item 9B.	Other Information	192
PART III		
Item 10.	Directors, Executive Officers and Corporate Governance	197
Item 11.	Executive Compensation	199
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	200
Item 13.	Certain Relationships and Related Transactions, and Director Independence	200
Item 14.	Principal Accounting Fees and Services	200

PART IV

Item 15.	Exhibits and Financial Statement Schedules	201
	Schedule II - Valuation and Qualifying Accounts	210
	Glossary of Terms	211
	Signatures	214
	Exhibit Index	217

Table of Contents

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These include, but are not limited to, future performance, revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management s beliefs as well as assumptions made by and information currently available to management. When used herein, the words anticipate, intend, estimate, believe, expect, plan, should, hypothetical, potential, forecast, project, variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission going forward, and reliability standards,

any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,

changes in federal and state environmental regulations that could increase our costs or limit operations of our generating units,

changes in nuclear regulation and/or developments in the nuclear power industry generally that could limit operations of our nuclear generating units,

actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,

any inability to balance our energy obligations, available supply and trading risks,

any deterioration in our credit quality,

availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,

any inability to realize anticipated tax benefits or retain tax credits,

changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,

- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- adverse changes in the demand for or price of the capacity and energy that we sell into wholesale electricity markets,
- increase in competition in energy markets in which we compete,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in discount rates and funding requirements, and
- changes in technology and customer usage patterns.

Additional information concerning these factors is set forth in Part I under Item 1A. Risk Factors.

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

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

Table of Contents

FILING FORMAT AND GLOSSARY

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

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, Power, PSE&G and PSEG Energy Holdings L.L.C. (Energy Holdings). Depending on the context of each section, references to we, us, and our relate to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 211.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the U.S. Securities and Exchange Commission (SEC). You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC s internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

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

As of and for the Year Ended December 31, 2010

Table of Contents

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

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

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

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

Table of Contents

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

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

BUSINESS OPERATIONS AND STRATEGY

Power

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

Products and Services

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

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

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

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

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

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

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

Table of Contents

How Power Operates

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

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

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

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

Generation Capacity

Our installed capacity utilizes a diverse mix of fuels: 45% gas, 27% nuclear, 18% coal, 9% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2010, excluding amounts related to the Texas generation facilities which are being sold, was approximately 56,700 GWh. The following table indicates the proportionate share of generating output by fuel type.

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

Table of Contents

While overall generation has increased over the past several years, the mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units.

Generation Dispatch

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 36% base load, 42% load following and 22% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

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

Unit	2010 Capacity Factor
Salem Unit 1	85.3%
Salem Unit 2	96.9%
Hope Creek	89.1%
Peach Bottom Unit 2	89.8%
Peach Bottom Unit 3	97.0%

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

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

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

Table of Contents

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

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

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO will dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased LMP in congested areas, reflecting the bid prices of those higher-cost generation units.

Table of Contents

This method of determining supply and pricing creates an environment in the markets such that natural gas prices often have a major impact on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will often translate into significant changes in the wholesale price of electricity. This can be seen in the graphs below which present historical annual spot prices and forward calendar prices as averaged over each year.

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

The prices reflected in the tables above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are highly volatile and there is no assurance that such prices will remain in effect nor that we will be able to contract output at these forward prices.

Fuel Supply

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

- purchase of uranium (concentrates and uranium hexafluoride);
- conversion of uranium concentrates to uranium hexafluoride;

enrichment of uranium hexafluoride; and

fabrication of nuclear fuel assemblies.

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

In order to minimize emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources was not available for this facility, our near-term operations would be adversely impacted. In the longer-term, additional material capital expenditures would be required to modify our Bridgeport 3 station to enable it to operate using a broader mix of coal sources. In the past, this coal was also used for our Hudson 2 unit; however, during 2010 we completed the installation of pollution control equipment at that facility which will provide us more flexibility in the types of coal we can use there in the future. For additional information see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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

We have 1.3 billion cubic feet-per-day of firm transportation capacity under contract to meet our obligations under the BGSS contract. On an as available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet. We supplement that supply with a total storage capacity of 78 billion cubic feet.

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

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Item 7. MD&A Overview of 2010 and Future Outlook and Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

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

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

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

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

Table of Contents

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

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

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

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

In addition to energy sales, we also earn revenue from capacity payments for our assets in the Northeast and Mid-Atlantic U.S. These payments are compensation for committing a portion of our capacity to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there is sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints, raising concerns about reliability and creating a more acute need for capacity. Previously, some generators, including us, announced the retirement or potential retirement of certain older generating facilities due to insufficient revenues to support their continued operation. To enable the continued availability of these facilities, in separate instances, both PJM and ISO-NE agreed to enter into Reliability-Must-Run (RMR) arrangements to compensate operators for those units contribution to reliability. While the RMRs for our units in the ISO-NE expired in 2010, the RMR arrangement for our Hudson 1 generating unit remains in effect and was recently extended until September 2012.

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

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

Delivery Year	**MW-day**	**kW-yr**
June 2010 to May 2011	$ 174.29	$ 63.62
June 2011 to May 2012	$ 110.00	$ 40.16
June 2012 to May 2013	$ 139.73	$ 51.70
June 2013 to May 2014	$ 245.00	$ 89.43

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

Table of Contents

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

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

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

- changes in load and demand;
- changes in the available amounts of demand response resources;
- changes in available generating capacity (including retirements, additions, derates, forced outages, etc.);
- increases in transmission capability between zones;
- changes to the pricing mechanism, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time; and
- changes driven by legislative and/or regulatory action, that permit states to subsidize local electric power generation through the consummation of standard offer capacity agreements.

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

Hedging Strategy

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

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

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

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

We have obtained price certainty for all of our PJM and New England capacity through May 2014 through the RPM and FCM pricing mechanisms.

We enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation. There is, however, variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units compared to all units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey electric delivery company, that is, the load that remains after some customers have chosen to be served directly by third party suppliers. The amount of power supplied varies based on the level of the delivery company s default load, which is affected by the number of customers who choose a third party supplier, as well as by other factors such as weather and the economy. Historically, the number of customers that have switched to third party suppliers was relatively constant, but in 2010, as market prices declined from past years historic highs, there has been an incentive for more of the smaller commercial and industrial electric customers to switch. In a falling price environment, this has a negative impact on Power s margins, as the anticipated BGS pricing is replaced by lower market pricing. We are unable to determine the degree to which this switching, or migration, will continue, but the impact on our results could be material.

To support our contracted sales of energy, we enter into contracts for the future purchase and delivery of our anticipated nuclear fuel and coal needs, which include some market-based pricing components. As of February 15, 2011, we had contracted for the following percentages of our nuclear and coal generation output and related fuel supplies for the next three years with modest amounts beyond 2013.

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

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as these units are generally dispatched when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units have generally provided a lower contribution to our margin than either the nuclear or coal units, although recent market price dynamics of coal and gas moderated this historical relationship for 2010.

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

Table of Contents

PSE&G

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

Products and Services

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

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

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

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

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

- a program to help finance the installation of solar power systems throughout our electric service area,
- a program to develop, own and operate solar power systems, and
- a set of energy efficiency programs to encourage conservation and energy efficiency by providing energy and money saving measures directly to businesses and families.

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

Table of Contents

How PSE&G Operates

We provide network transmission and point-to-point transmission services, which are coordinated with PJM, and provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our existing and future transmission investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Currently, approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn incentive rates. For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation Transmission Regulation.

Transmission Statistics

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

Distribution

Our primary business is the distribution of gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described below for 2010. We believe that we have all the non-exclusive franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

	% of 2010 Sales	
Customer Type	**Electric**	**Gas**
Commercial	57%	36%
Residential	33%	61%
Industrial	10%	3%
Total	**100%**	**100%**

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

Electric and Gas Distribution Statistics

	December 31, 2010 Number of Customers	Electric Sales and Gas Sold and Transported	Historical Annual Load Growth 2006-2010
Electric	2.2 Million	43,645 GWh	-0.5%
Gas	1.8 Million	3,465 Million Therms	-1.0%

13

Table of Contents

Supply

Although commodity revenues make up more than 59% of our revenues, we make no profit on the supply of energy since the actual costs are passed through to our customers.

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

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

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

Markets and Market Pricing

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

Table of Contents

Energy Holdings

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

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

Products and Services

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

Our leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented in our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the U.S., the lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk Credit Risk Energy Holdings, Item 8. Financial Statements and Supplementary Data Note 8. Financing Receivables and Note 13. Commitments and Contingent Liabilities.

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

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

Table of Contents

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

COMPETITIVE ENVIRONMENT

Power

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

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

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

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, customer migration and other factors. It is also possible that advances in technology, such as distributed generation, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing transmission planning or cost allocation could also impact our revenues.

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

Environmental issues, such as restrictions on carbon dioxide (CO_2) emissions and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. While our generation fleet is relatively low-emitting, additional restrictions could have a negative impact on certain of our units, including our coal units.

Table of Contents

In addition, pressures from renewable resources, such as wind and solar, could increase over time, especially if government incentive programs continue to grow. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator, the California ISO and the PJM region, have either implemented or are considering implementing changes to their respective regional transmission planning processes that will enable the construction of large amounts of transmission to move renewable generation to load centers. The FERC is considering ordering all FERC-jurisdictional regions to effectuate such changes to the planning processes to facilitate the integration of renewable resources. See discussion in Regulatory Issues Federal Regulation below.

PSE&G

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

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

EMPLOYEE RELATIONS

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

Employees as of December 31, 2010

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,292	1,178	18	1,026
Union	1,511	4,931	0	9
Total Employees	**2,803**	**6,109**	**18**	**1,035**
Number of Union Groups	3	5	N/A	1

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

REGULATORY ISSUES

Federal Regulation

FERC

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

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where

17

Table of Contents

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

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

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

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

Regulation of Wholesale Sales Generation/Market Issues

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

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

Under MBR rules, FERC may look at sub-markets to analyze whether a company possesses market power. Applying these rules in October 2008, FERC granted PSE&G, PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC continued MBR authority and granted both PSEG Fossil LLC and PSEG Nuclear LLC initial MBR authority. Each of these companies filed for an update of its MBR authority in December 2010. Interventions and comments with respect to this MBR filing are due at the FERC by the end of February. A decision is expected in 2011.

- ***Cost-Based RMR Agreements*** FERC has permitted public utility generation owners to enter into RMR agreements that provide cost-based compensation to a generation owner when a unit proposed for retirement is asked to continue operating for reliability purposes. On November 11, 2010, PJM officially notified Power that it will need the Hudson 1 generating station to remain in service through September 1, 2012 to ensure grid reliability during the summer of 2012 given the delays associated with the Susquehanna-Roseland project. In January 2011, Power filed at FERC for extension of the RMR agreement for Hudson Unit 1 through September 1, 2012.

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

Table of Contents

Energy Clearing Prices

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

Capacity Market Issues

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

RPM is a locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. PJM s RPM and related FERC orders establishing prices paid to us and other generators as a result of RPM s transitional auctions were challenged in court by various state public utility commissions, including the BPU. On February 8, 2011 the DC Circuit Court of Appeals issued a decision upholding FERC orders denying this challenge to the transitional auction results. Moreover, the mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active, and there is currently significant discussion about the future role of demand response in the RPM market.

Pursuant to a settlement that established the design of ISO-NE s market for installed capacity and which was implemented gradually over a four-year period that commenced in December 2006, all generators in New England began receiving fixed capacity payments that escalate gradually over the transition period. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of generators on the system and contains incentive mechanisms to encourage generator availability during generation shortages. As in PJM, capacity market rules in the ISO-NE continue to develop. Power has challenged in court the results of the ISO-NE s first forward capacity auction, arguing that its units received inadequate compensation notwithstanding the location of its resources in a constrained area. This case is pending at the D.C. Circuit Court of Appeals. Power and other generators have also filed a complaint at FERC regarding the ISO-NE s capacity market design, alleging that it insufficiently reflects locational capacity values. This complaint is also pending.

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

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

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

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are then trued up the following year to reflect actual annual expenses/capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments, and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments. For additional information on our transmission rates and the annual true-ups, see Item 7. MD&A Overview of 2010 and Future Outlook.

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

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

Transmission Expansion In June 2007, PJM identified the need for the construction of the Susquehanna-Roseland line, a new 500 kV transmission line intended to maintain the reliability of the electrical grid serving New Jersey customers. PJM assigned construction responsibility for the new line to us and PPL for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is up to $750 million, and PJM had originally directed that the line be placed into service by June 2012. Construction of the Susquehanna-Roseland line is contingent upon obtaining all necessary federal, state, municipal and landowner permits and approvals. The construction of the line has encountered local opposition. In February 2010, we received approval from the BPU to construct our portion of the project, which was memorialized by a written order in April 2010. Regarding environmental approvals, in June 2009, the New Jersey Highlands Council provided a favorable applicability determination with respect to the portion of the project crossing the Highlands region which was approved by the New Jersey Department of Environmental Protection (NJDEP) in January 2010. However, we have not received certain environmental approvals that are required for each of the Eastern and Western segments of the line and believe it is unlikely that we will obtain these approvals until late 2012, at the earliest. The Western portion of the line also requires certain permits from the National Park Service, whose review is not expected to be completed until late 2012. Consequently, at this time, we do not expect the Eastern portion of the line to be in service before June 2014, and do not expect the Western portion to be in service before June 2015. Further delays are possible for both portions. Delays in the construction schedule could impact the timing of expected transmission revenues.

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

FERC has granted our request for incentive rate treatment for the Susquehanna-Roseland line, including an adder of 125 basis points above our base ROE, recovery of 100% of Construction Work in Progress (CWIP) in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the project is abandoned or cancelled, in whole or in part, for reasons beyond our control.

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

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

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

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

Table of Contents

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

Compliance

Reliability Standards Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts. Many reliability standards have been developed and approved. These standards apply both to reliability of physical assets interconnected to the bulk power system and to the protection of critical cyber assets. Our California generation assets, as well as our New Jersey utility operations, have already undergone formal audits, and our generation assets in PJM, ISO-NE and the NYISO will be audited in 2011. In addition, many of our operating companies have been subject to spot audits. NERC compliance represents a significant area of compliance responsibility for us and a challenging one. As new standards are developed and approved, existing standards are revised and registration requirements are modified which could increase our compliance responsibilities.

Commodity Futures Trading Commission (CFTC)

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

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

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

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

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

Table of Contents

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. In August 2009, we submitted applications to extend the operating licenses of our Salem and Hope Creek facilities by 20 years. No parties have requested a hearing or intervention and the initial filing deadline for such a request as part of the NRC license renewal process has passed. The NRC is expected to spend up to 30 months to review our applications before making a decision. The current operating licenses of our nuclear facilities expire in the years shown below:

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

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

State Regulation

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

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

Rates

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Recent Rate Adjustments

USF/Lifeline The USF is an energy assistance program mandated by the BPU to provide payment assistance to low income customers. The Lifeline program is a separately mandated energy assistance program to provide payment assistance to elderly and disabled customers. On June 30, 2010, the State s electric and gas utilities filed to reset the statewide rates for the USF and the Lifeline program.

Table of Contents

The filed rates were subsequently updated and approved effective November 1, 2010 in a written Order dated October 20, 2010. The filed rates were set to recover $215 million on a statewide basis. Of this amount, the revised statewide electric rates will recover $150 million and the statewide gas rates will recover $65 million. The rates for the Lifeline program are set to recover $73 million; $49 million and $24 million for electric and gas respectively. We earn no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.

SBC/NGC In February 2009, we filed a petition requesting a decrease in our electric SBC/NGC rates of $18.9 million and an increase in gas SBC rates of $3.7 million. In July 2009, a revision was filed requesting an increase in SBC/NGC rates of $104 million and $15 million for electric and gas, respectively. The electric increase was due to increased non-utility generation (NUG) contract costs. The Administrative Law Judge (ALJ) issued an initial decision in April 2010 that recommended a revenue increase of $119 million and a disallowance of approximately $254,000 in PJM costs from the NGC and approximately $540,000 of interest that accrued on the electric SBC. Although PSE&G filed exceptions to the recommendation, the BPU issued a written order in June 2010, adopting the ALJ s initial decision. PSE&G filed a notice of appeal in August 2010 regarding the disallowances related to the NGC and electric SBC. We cannot predict the outcome of this appeal.

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

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

RAC In November 2009, we filed a RAC 17 petition with the BPU requesting an increase in electric and gas RAC rates of approximately $13 million and $11 million, respectively. In August 2010, the BPU issued an order approving a settlement agreement which provides for the recovery of $24 million for the twelve months ended July 2009.

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

Energy Supply

BGS New Jersey s EDCs provide two types of BGS, the default electric supply service for customers who do not have a third party supplier. The first type, which represents about 82% of PSE&G s load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Fixed Price). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

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

Table of Contents

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

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

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

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

For additional information, see Item 8. Financial Statements and Supplementary Data Note 6. Regulatory Assets and Liabilities and Note 13. Commitments and Contingent Liabilities.

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

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

In July 2010, PSE&G self-implemented a reduction in the BGSS rate. The reduction targets an approximate $90 million decrease in the BGSS deferred balance on an annual basis. The reduction in the BGSS-Residential Service Gas (RSG) Commodity Charge for a typical gas residential heating customer was a decrease of approximately 5%.

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

Energy Policy

New Jersey Energy Master Plan (EMP) New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. The most recent EMP was finalized in October 2008. The plan identifies a number of the actions to improve energy efficiency, increase the use of renewable resources, ensure a reliable supply of energy and stimulate investment in clean energy technologies.

We have approval from the BPU to implement several programs addressing different components of the EMP goals to improve efficiencies in customer use and increase the level of renewable generation in New Jersey.

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

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

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

The total investment of both phases of the Solar Loan Program will be approximately $250 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2010, we have provided a total of $70 million in loans for 196 projects representing 19 MW.

The second solar initiative is the Solar 4 All Program that was approved by the BPU in July 2009. Under this program, we are investing approximately $465 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of systems 500kW or greater installed on PSE&G-owned property (25 MW), solar panels installed on distribution system poles (40 MW) and PV systems installed on third-party sites in our electric service territory (15 MW). We will sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition we will sell the SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales will be used to offset program costs.

As of December 31, 2010, 15 MW of solar panels had been installed on distribution poles with an investment of approximately $110 million. In addition during 2010, 13 MW representing 11 projects were placed in service with an investment of approximately $70 million. An additional 6 MW is expected to be placed into service in the first quarter of 2011 and additional projects are in various stages of negotiation and development.

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

In July 2009, the BPU approved a portion of our program that focuses on air conditioning load control in the residential and small commercial customer segments. The investment represents $65.3 million with a target of 150 MW to be achieved.

In October 2010 we petitioned the BPU to expand the number of participants in the residential cycling program by 57,000 for a total of approximately 225,000 residential participants, due to a lower per-unit

Table of Contents

installation cost. The request is still pending. The remainder of our original filing has been inactive at the BPU since July 2009. As of December 31, 2010, we had installed approximately 19 MW.

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

Energy Efficiency Economic Stimulus Program In July 2009, the BPU approved our energy efficiency program developed to stimulate economic growth in the state. Under this program, we anticipated approximately $166 million in energy efficiency capital expenditures over an 18-month period. The program provides for a charge for recovery of program expenditures plus an allowed return. As of December 2010, $100 million of the $166 million had been invested. The initiatives target multiple customer segments. Subprograms provide energy audits and incentives for energy retrofit services to homes and small businesses in Urban Enterprise Zone municipalities, multi-family buildings, hospitals, data centers and governmental entities. Other initiative components include funding for new technologies and demonstration projects, and a program to encourage non-residential customers to reduce energy use through improvements in the operation and maintenance of their facilities.

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

Carbon Abatement Program The BPU approved our proposal to invest up to $46 million over four years on a small scale carbon abatement program across specific customer segments. For each year of the program we will file a petition on October 1 to set forth the calculation of the electric and gas recovery charges for the subsequent year. The BPU approved a rate increase in December 2009, which resulted in a net annual revenue increase of $1.9 million in 2010. The petition filed in October 2010 for setting the recovery charges for 2011 is still pending. As of December 31, 2010, $20 million of the approved $46 million investment had been spent on energy efficiency measures.

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

In April 2009, the BPU approved a settlement agreement which identified 38 qualifying projects totaling $694 million. The CAC will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting.

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

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

Table of Contents

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

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

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

Consolidated Tax Adjustments

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

BPU Audits

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

Management/Affiliate Audit The BPU engaged a contractor to perform a comprehensive audit with respect to the effectiveness of management and transactions among affiliates, which began in October 2009. We expect that a draft report will be issued during 2011. The report can be expected to include recommendations for changes in practices at PSE&G and its affiliates. We will have an opportunity to provide comments. The BPU may enforce the findings in whole or in part by Order.

Deferral Audit The BPU Energy and Audit Division conducted audits of electric deferred balances that occurred during the four year transition period from 1999 through 2003. A draft Deferral Audit Phase II report relating to the 12-month period ended July 31, 2003 was released by the consultant to the BPU in April 2005. Effectively, this audit was closed with the resolution of the Market Transition Charge issues. See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for additional information.

RAC Audit In February 2008, the BPU s Division of Audits commenced a review of the RAC program for the RAC 12, 13 and 14 periods encompassing August 1, 2003 through July 31, 2006. Total RAC costs associated with this period were $83 million. In August 2010 we received a No Action letter from the BPU stating that no material issues were found and the BPU staff now considers the audit to be closed.

ENVIRONMENTAL MATTERS

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

Table of Contents

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

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

For additional information related to environmental matters, including anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

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

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

Clean Air Interstate Rule (CAIR) Since 2009, the EPA has regulated nitrogen oxide (NO_x) emissions and starting in 2010, regulated sulfur dioxide (SO_2) emissions to reduce interstate air pollution transport among the 28 central and northeastern states and the District of Columbia. Our generating stations in Connecticut, New Jersey and New York are affected sources in the regulation. The purpose of the regulation is to improve Ozone and Fine Particulate (PM2.5) air quality within states that have not demonstrated achievement of National Ambient Air Quality Standards (NAAQS). CAIR was implemented through a cap-and-trade program and to date the impact has not been material to us as the allowances allocated to our stations were sufficient. If 2011 operations are similar to 2009 and 2010, it is expected that the impact to operations from CAIR will not be significant. Starting January 2012, CAIR is expected to be replaced by the Clean Air Transport Rule (see below).

New Jersey NOx Regulation: High Electric Demand Day (HEDD) In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel fired electric generation units. The rule has a significant impact on Power s generation fleet, as it imposes NO_x emissions limits that will require significant capital investment for controls or the retirement of 102 combustion turbines (approximately 2,000 MW) and five older New Jersey steam electric generation units (approximately 800 MW) by April 2015. We have been working with the NJDEP throughout the development of this rulemaking to minimize financial impact and to provide for transitional lead time to address the retirement of electric generation units. Power cannot predict the financial impact resulting from compliance with this rulemaking.

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

Table of Contents

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

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

Climate Change

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

States rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, and 2011). Allowances are available through the auction or through secondary markets and are required to be submitted to states by March 2012 for the first period.

Pricing for the allowances will vary based on future allowance market conditions, electric generation market conditions and the possibility of a national greenhouse gas (GHG) program that may or may not supplant RGGI. For the first three-year compliance period, we have acquired sufficient allowances to compensate for CO_2 emissions from affected sources.

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

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

Table of Contents

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

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

CO_2 Litigation In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving our companies could be material to the future liability of energy companies. Litigation has been commenced by individuals, local governments and interest groups alleging that various industries, including various energy companies, emitted greenhouse gases causing global climate change that resulted in a variety of damages. If relevant federal or state common law were to develop that imposed liability upon those that emit greenhouse gases for alleged impacts of greenhouse gas emissions, such potential liability to us could be material.

Water Pollution Control

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

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

For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

Table of Contents

Hazardous Substance Liability

The production and delivery of electricity, distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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

Natural Resource Damages CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change.

Fuel and Waste Disposal

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

The Nuclear Waste Fee litigation is not expected to have any effect on Power s September 2009 settlement agreement with DOE applicable to Salem and Hope Creek under which Power will be reimbursed for past and future reasonable and allowable costs resulting from the DOE delay in accepting spent nuclear fuel for permanent disposition. A similar settlement agreement was reached related to Peach Bottom in 2004.

Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away-from reactor sites for at least 30 years beyond the licensed life for the reactor. We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

Table of Contents

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

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

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Note 22. Financial Information by Business Segment.

ITEM 1A. RISK FACTORS

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

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

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

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

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

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

We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

Comply with regulatory requirements There are Federal standards in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by NERC for compliance. FERC can impose penalties up to $1 million per day per violation. Further, FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, interlocking directorate rules and cross-subsidization.

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

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

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

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

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

In the markets where we operate, natural gas prices typically have a major impact on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will usually translate into significant changes in the wholesale price of electricity.

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

In recent years, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units.

Also, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2010, it may have had to provide approximately $828 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the Commodity Futures Trading Commission which are expected to be implemented later in 2011.

Table of Contents

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

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

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

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

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

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

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

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

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

37

Table of Contents

Potential closed-cycle cooling requirements Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million.

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

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

Remediation of environmental contamination at current or formerly owned facilities We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been deposited and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. Recent amendments to New Jersey law now place affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances. While those amendments do not change our liability, they do impact the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow.

In 2007, the State of New Jersey filed multiple lawsuits against parties, including us, who were alleged to be responsible for injuries to natural resources in New Jersey, including a site being remediated under our MGP program. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

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

Coal Ash Management Coal ash is a CCR produced as a byproduct of generation at our coal-fired facilities. We currently have a program to beneficially reuse coal ash as presently allowed by federal and state regulations. In June 2010, the EPA formally published a proposed rule in the Federal Register offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste and the other two options are variations of a non-hazardous designation. All options communicate the EPA s intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human

Table of Contents

health and the environment. The outcome of the EPA rulemaking cannot be predicted. Proposed regulations which more stringently regulate coal ash, including regulating coal ash as hazardous waste, could materially increase costs at our coal-fired generation facilities.

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

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

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

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

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

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

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

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

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Various rules have recently been implemented to respond to commodity pricing, reliability and other industry concerns. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in

Table of Contents

constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM s locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

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

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

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

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

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

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

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Developers of long-distance green transmission projects are seeking inclusion in regional transmission planning processes, with the potential to move lower-cost generation to eastern markets, including New Jersey and New York. Moreover, the FERC has a pending rulemaking proceeding to consider requiring changes to transmission planning processes so that more transmission can be built to facilitate renewable generation development. In addition, the DOE-funded Eastern Interconnection Planning Collaborative (EIPC) continues its efforts to study transmission planning across the Eastern Interconnection, making the construction of large-scale transmission more likely. In addition, pressures from renewable resources such as wind and solar, could increase over time, especially if government incentive programs continue to grow.

Table of Contents

We face significant competition in the merchant energy markets.

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

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

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

- ***DSM and other efficiency efforts*** DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers usage could result in a reduction in load requirements.
- ***Changes in technology and/or customer conservation*** It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, such as fuel cells, microturbines, windmills and PV (solar) cells, to a level that is competitive with that of most central station electric production. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology could also alter the channels through which retail electric customers buy electricity, which could adversely affect financial results.

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

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

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

If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These cannot be predicted with certainty.

Table of Contents

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

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

Capital for projects and investments has been provided primarily by internally-generated cash flow and borrowings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt, financing for projects and investments or funding the equity commitments required for such projects and investments in the future.

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

The performance of the capital markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets similar to the one experienced in 2008 could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

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

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

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

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

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

Table of Contents

Acts of war or terrorism could adversely affect our operations.

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

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

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

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

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

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

- breakdown or failure of equipment, processes or management effectiveness;
- disruptions in the transmission of electricity;
- labor disputes;
- fuel supply interruptions;
- transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements;
- permit limitations; and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, acts of terrorism or other similar occurrences.

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

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

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

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

The IRS has issued reports with respect to its audits of PSEG s consolidated federal corporate income tax returns for tax years 1997 through 2003, which disallowed all deductions associated with certain lease transactions. The IRS reports also proposed a 20% penalty for substantial understatement of tax liability. PSEG has filed protests of these findings with the Office of Appeals of the IRS.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, Power and PSE&G

None.

ITEM 2. PROPERTIES

All of our physical property is owned by our subsidiaries. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

Table of Contents

Generation Facilities

As of December 31, 2010, Power s share of summer installed generating capacity was 13,538 MW, as shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	930	100%	930	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone(A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh(A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	514	100%	514	Coal/Oil	Base Load/Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**6,399**		**3,753**		
Nuclear:						
Hope Creek	NJ	1,197	100%	1,197	Nuclear	Base Load
Salem 1 & 2	NJ	2,337	57%	1,342	Nuclear	Base Load
Peach Bottom 2 & 3(B)	PA	2,245	50%	1,122	Nuclear	Base Load
Total Nuclear		**5,779**		**3,661**		
Combined Cycle(C):						
Bergen	NJ	1,178	100%	1,178	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	755	100%	755	Gas	Load Following
Total Combined Cycle		**3,163**		**3,163**		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	504	100%	504	Gas	Peaking
Kearny	NJ	446	100%	446	Gas	Peaking
Burlington	NJ	557	100%	557	Oil/Gas	Peaking
Linden	NJ	336	100%	336	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem	NJ	38	57%	22	Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		**2,777**		**2,761**		
Pumped Storage:						
Yards Creek(D)	NJ	400	50%	200		Peaking
Total Operating Power Plants		**18,518**		**13,538**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation

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

(D) Operated by Jersey Central Power and Light Company

Table of Contents

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

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

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

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
United States					
Kalaeloa	HI	208	50%	104	Oil
GWF	CA	105	50%	53	Petroleum coke
Hanford L.P. (Hanford)	CA	27	50%	13	Petroleum coke
Bridgewater	NH	16	40%	6	Biomass
Conemaugh	PA	15	4%	1	Hydro
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Total United States		**400**		**206**	
International					
Turboven	Venezuela	120	50%	60	Natural gas
Turbogeneradores de Maracay (TGM)	Venezuela	40	9%	4	Natural gas
Total International		**160**		**64**	
Total Operating Power Plants		**560**		**270**	

Transmission and Distribution Facilities

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

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

Table of Contents

As of December 31, 2010, the daily gas capacity of PSE&G s 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas and liquefied natural gas and aggregated 2,973,000 therms (288,640,800 cubic feet on an equivalent basis of 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	773,000
Camden LPG	Camden, NJ	280,000
Central LPG	Edison Twp., NJ	960,000
Harrison LPG	Harrison, NJ	960,000
Total		**2,973,000**

As of December 31, 2010, PSE&G owned and operated 17,608 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, all in three operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

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

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

In addition, as of December 31, 2010, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 23,543 megavolt-amperes and 246 substations with an aggregate installed capacity of 8,179 megavolt-amperes. In addition, four substations in New Jersey having an aggregate installed capacity of 109 megavolt-amperes were operated on leased property.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

LCAPP

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

Table of Contents

Electric Discount and Energy Competition Act (Competition Act)

In April 2007, PSE&G and Transition Funding were served with a purported class action complaint (Complaint) in New Jersey Superior Court challenging the constitutional validity of certain stranded cost recovery provisions of the Competition Act, seeking injunctive relief against continued collection from PSE&G s electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional.

In July 2007, the plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes as well as recovery of such taxes previously collected. In July 2007, PSE&G filed a motion to dismiss the amended Complaint, which was granted in October 2007. In November 2007, the plaintiff filed a notice of appeal with the Appellate Division of the New Jersey Superior Court. In February 2009, the New Jersey Appellate Division affirmed the decision of the lower court dismissing the case. In May 2009, the New Jersey Supreme Court denied a request from the plaintiff to review the Appellate Division s decision.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same stranded cost charges. In September 2007, PSE&G filed a motion with the BPU to dismiss the petition. In June 2010, the BPU granted PSE&G s motion to dismiss. PSE&G has not yet received the written order from the BPU memorializing its decision.

Con Edison (Con Ed)

In 2001, Con Ed filed a complaint with FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. On September 16, 2010, FERC approved a settlement agreement entered into by PSE&G, Con Ed, PJM, NYISO and others. This settlement provides the basis for moving forward with Con Ed after the current contracts expire in 2012 and settles all issues associated with the existing contracts, including cases pending in the D.C. Circuit Court of Appeals. However, dismissal of these court cases is contingent upon receipt of a final, non-appealable order from the FERC. One party to the proceeding has sought rehearing of the FERC approval order and will likely appeal an adverse decision on rehearing. As a result, the settlement has not yet taken effect and may not take effect for some time.

Environmental Matters

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

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

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

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

Table of Contents

(4) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA s selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2013 at an estimated cost of $1 million.

(5) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G s Trenton Switching Station property. In 1996, PSE&G entered into a memorandum of agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination. Anticipated future activities at the site include the filing of certification(s) with NJDEP once every two years regarding the effectiveness of engineering and institutional controls, quarterly groundwater monitoring for several years and the installation of additional off-site groundwater monitoring wells as directed by NJDEP.

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

(7) In 1996, Morton International, Inc., a subsidiary of The Dow Chemical Company, filed a lawsuit against the former customers of a former mercury refining operation located on the banks of Berry s Creek in Wood-Ridge, New Jersey. The lawsuit seeks to recover cleanup costs incurred and to be incurred in remediating the site. PSE&G was among the former customers sued based on allegations that mercury originating at its Kearny Generating Station was sent to the site for refining.

(8) The EPA sent Power, PSE&G and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry s Creek in Bergen County, New Jersey and requesting that the PRPs perform a RI/FS on Berry s Creek and the connected tributaries and wetlands. Berry s Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could be completed in approximately five years at a total cost of approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent to conduct the RI/FS.

(9) In 2004, Exelon Generation signed an agreement for Peach Bottom regarding the DOE s delay in accepting spent nuclear fuel for permanent storage. Under the agreement, Exelon Generation would be reimbursed for costs previously incurred, with future costs incurred resulting from the DOE delays in accepting spent fuel to be reimbursed annually until the DOE fulfills its obligation. In addition, Exelon Generation and Power are required to reimburse the DOE for the previously received credits from the Nuclear Waste Fund. In September 2009, Power signed an agreement with the DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE s delay in accepting spent nuclear fuel for permanent disposition. For additional information, see Item 8. Financial Statements and Supplementary Data Note 13. Commitments and Contingent Liabilities.

(10) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with NJDEP Solid Waste Regulations.

Table of Contents

PART II

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

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2010, there were 81,659 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2005 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

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

Table of Contents

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

Common Stock	High	Low	Dividend per Share
2010			
First Quarter	$ 33.75	$ 29.01	$ 0.3425
Second Quarter	$ 34.21	$ 29.02	$ 0.3425
Third Quarter	$ 34.93	$ 30.92	$ 0.3425
Fourth Quarter	$ 33.97	$ 30.35	$ 0.3425
2009			
First Quarter	$ 33.66	$ 23.65	$ 0.3325
Second Quarter	$ 33.94	$ 27.85	$ 0.3325
Third Quarter	$ 34.02	$ 30.38	$ 0.3325
Fourth Quarter	$ 34.14	$ 29.20	$ 0.3325

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

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

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

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

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders	3,660,634	$ 32.22	17,930,109(A)
Equity compensation plans not approved by security holders	0	$ 0.00	3,589,032(B)

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

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

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data Note 18. Stock Based Compensation.

Power

We own all of Power s outstanding limited liability company membership interests. For additional information regarding Power s ability to pay dividends, see Item 7. MD&A Overview of 2010 and Future Outlook.

Table of Contents

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G s ability to continue to pay dividends, see Item 7. MD&A Overview of 2010 and Future Outlook.

ITEM 6. SELECTED FINANCIAL DATA

PSEG

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