SYPRIS SOLUTIONS INC
Form 8-K
March 13, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): March 9, 2009

Sypris Solutions, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or Other Jurisdiction of Incorporation)	0-24020 (Commission File Number)	61-1321992 (I.R.S. Employer Identification No.)
101 Bullitt Lane, Suite 450 Louisville, Kentucky (Address of Principal Executive Offices)		40222 (Zip Code)

Registrant’s telephone number, including area code: (502) 329-2000

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 5 – Corporate Governance and Management

Item 5.02(e) Departure of Directors or Certain Executive Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

Effective as of March 9, 2009, Sypris Solutions, Inc. (the "Company") entered into an employment agreement ("Employment Agreement") with participants in the Company's Executive Long-Term Incentive Program ("ELTIP") for 2009 (the "2009 ELTIP"). Each participant in the 2009 ELTIP, including named executive officers John R. McGeeney and Richard L Davis, and Chief Financial Officer Brian A. Lutes, executed an employment agreement, with the exception of Jeffrey T. Gill, the Company's President and Chief Executive Officer. The form of employment agreement is attached to this Report as Exhibit 99.1 and incorporated by reference herein.

Each Employment Agreement is for a term of one year and provides that if, during the term of the Employment Agreement, the employee's employment is terminated without Cause (as defined in the Employment Agreement) then (i) the employee will continue to receive his current salary for a period of 12 months following the date of termination, provided that if the employee becomes employed by another entity during such time, the employee will only receive 30% of such salary, and (ii) all of the employee's outstanding restricted stock and stock options will become 100% vested and remain exercisable until the expiration date then in effect for such stock or options. The Employment Agreements also contain confidentiality, non-compete and non-solicitation covenants by the employee during the term of the agreement.

Section 9– Exhibits

Item 9.01 Financial Statements and Exhibits.

(c) Exhibits

99.1 Form of Employment Agreement

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Sypris Solutions, Inc.

Dated: March 13, 2009	By:	/s/ John R. McGeeney John R. McGeeney General Counsel and Secretary

INDEX TO EXHIBITS

Exhibit Number	Description
99.1	Form of Employment Agreement

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Power

Guarantor Subsidiaries

Other Subsidiaries

Consolidating Adjustments

Consolidated

Millions

Six Months Ended June 30, 2011

Operating Revenues

$0 $3,897 $77 $(722) $3,252

Operating Expenses

1 3,037 80 (722) 2,396

Operating Income (Loss)

(1) 860 (3) 0 856

Equity Earnings (Losses) of Subsidiaries

602 59 0 (661) 0

Other Income

19 121 0 (21) 119

Other Deductions

(3) (23) 0 0 (26)

Other-Than-Temporary Impairments

(1) (2) 0 0 (3)

Interest Expense

(82) (21) (10) 21 (92)

Income Tax Benefit (Expense)

35 (392) 5 0 (352)

Income (Loss) on Discontinued Operations, net of tax

0 0 67 0 67

Net Income (Loss)

$569 $602 $59 $(661) $569

Six Months Ended June 30, 2011

Net Cash Provided By (Used In) Operating Activities

$367 $1,400 $(148) $(473) $1,146

Net Cash Provided By (Used In) Investing Activities

$589 $(674) $317 $(413) $(181)

Net Cash Provided By (Used In) Financing Activities

$(956) $(725) $(168) $887 $(962)

Six Months Ended June 30, 2010

Operating Revenues

$0 $4,036 $65 $(641) $3,460

Operating Expenses

0 3,029 73 (641) 2,461

Operating Income (Loss)

0 1,007 (8) 0 999

Equity Earnings (Losses) of Subsidiaries

590 (18) 0 (572) 0

Other Income

18 85 0 (21) 82

Other Deductions

(1) (26) 0 0 (27)

Other-Than-Temporary Impairments

0 (6) 0 0 (6)

Interest Expense

(65) (26) (12) 21 (82)

Income Tax Benefit (Expense)

26 (426) 7 0 (393)

Income (Loss) on Discontinued Operations, net of tax

0 0 (5) 0 (5)

Net Income (Loss)

$568 $590 $(18) $(572) $568

Six Months Ended June 30, 2010

Net Cash Provided By (Used In) Operating Activities

$45 $1,297 $(13) $(575) $754

Net Cash Provided By (Used In) Investing Activities

$(29) $(885) $0 $319 $(595)

Net Cash Provided By (Used In) Financing Activities

$(17) $(421) $(33) $256 $(215)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of June 30, 2011					
Current Assets	$ 3,787	$ 6,930	$ 1,052	$ (9,417)	$ 2,352
Property, Plant and Equipment, net	56	5434	920	0	6,410
Investment in Subsidiaries	4,395	937	0	(5,332)	0
Noncurrent Assets	153	1,625	45	(68)	1,755
Total Assets	**$ 8,391**	**$ 14,926**	**$ 2,017**	**$ (14,817)**	**$ 10,517**
Current Liabilities	$ 787	$ 9,174	$ 945	$ (9,417)	$ 1,489
Noncurrent Liabilities	250	1,359	132	(67)	1,674
Long-Term Debt	2,140	0	0	0	2,140
Member s Equity	5,214	4,393	940	(5,333)	5,214
Total Liabilities and Member s Equity	**$ 8,391**	**$ 14,926**	**$ 2,017**	**$ (14,817)**	**$ 10,517**
As of December 31, 2010					
Current Assets	$ 3,988	$ 6,807	$ 1,117	$ (8,468)	$ 3,444
Property, Plant and Equipment, net	55	5,385	902	0	6,342
Investment in Subsidiaries	4,794	1,079	0	(5,873)	0
Noncurrent Assets	170	1,549	41	(94)	1,666
Total Assets	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**
Current Liabilities	$ 751	$ 8,519	$ 849	$ (8,468)	$ 1,651
Noncurrent Liabilities	423	1,510	129	(93)	1,969
Long-Term Debt	2,805	0	0	0	2,805
Member s Equity	5,028	4,791	1,082	(5,874)	5,027
Total Liabilities and Member s Equity	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

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

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

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid Atlantic United States,
- **PSE&G,** our public utility company which provides transmission and distribution of electric energy and gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- **Energy Holdings,** which owns our energy-related leveraged leases and other investments.

Our discussion in Part I, Item 1. Business of our 2010 Annual Report on Form 10-K provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets. Our risk factors section in Part II Item 1A provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2010 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2011 and any changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This information should be read in conjunction with such Statements, Notes and the 2010 Annual Report on Form 10-K.

OVERVIEW OF 2011 AND FUTURE OUTLOOK

During the first half of 2011, we continued to be impacted by lower pricing at Power. We began experiencing a greater pricing impact due to a significant decline in both PJM Reliability Pricing Model (RPM) and Basic Generation Service (BGS) rates which became effective in the second quarter. Our pricing also continues to be impacted by customer migration away from our BGS supply contracts as these volumes are replaced with lower priced spot market sales. However, the impact of migration on our results has been reduced as average BGS rates decline to a level more closely resembling current market prices so that customers also have less incentive to choose third party suppliers.

Partially offsetting this lower pricing at Power are higher distribution rates at PSE&G as a result of the base rate case settlement in mid-2010. This included an increase of $73.5 million and $26.5 million in annual electric and gas revenues, respectively, with a return on equity (ROE) of 10.3%. We have also realized an increase in transmission revenues as a result of our 2011 Formula Rate Update which provides for approximately $45 million in increased revenues in our 2011 transmission rates effective January 1, 2011.

In addition, our gas sales volumes improved for the first half of 2011 compared to the same period in 2010, due primarily to much warmer winter weather last year. Heating degree days, as a measure of winter weather in 2011, were 8% higher than in 2010. The gas weather normalization clause, which was implemented effective with the base rate case settlement last year, added $7 million to margin due to the fact that heating degree days were 2% below normal in 2011. The weather, the economy and other factors all contributed to an overall increase of approximately 4% in Power s Basic Gas Supply Service (BGSS) sales volumes and PSE&G s gas delivery volumes as compared to 2010.

For 2011 and beyond, the key issues our business will confront are:

- potential for sustained lower natural gas and electricity prices, uncertainty in the economic recovery,

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- regulatory and political uncertainty, particularly around energy policy and environmental regulation, and
- pressure on competitive markets in many states, including New Jersey.

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

- focus on controlling costs while maintaining our safety, reliability and compliance standards,
- successfully recontract open positions, and
- execute our capital investment program, including continued investments for growth that yield contemporaneous returns.

There have also been other significant regulatory and legislative developments during the year which may affect our operations in the future as new rules and regulations are adopted. For additional information on these issues, see Part II, Item 5. Other Information.

- In an attempt to stimulate the development of new generation capacity in New Jersey through a subsidized rate mechanism, in January 2011, New Jersey enacted the long-term capacity agreement pilot program Act (LCAPP) directing the New Jersey Board of Public Utilities (BPU) to conduct a process to procure and subsidize up to 2,000 megawatts of baseload or mid-merit electric power generation. This could result in artificially depressed pricing in the competitive wholesale market and thus has the potential to harm competitive markets, on both a short-term and a long-term basis. In March 2011, the BPU issued a written order approving a form of agreement and selecting three generators to build a total of 1,949 MW of new combined-cycle generating facilities located in New Jersey. Power and PSE&G appealed this order. Each of the New Jersey electric distribution companies (EDCs), including PSE&G, executed standard offer capacity agreements (SOCA) with the three generators in compliance with the BPU s directive, but did so under protest reserving its legal rights. On April 27, 2011, the BPU approved the executed contracts and also announced its intent to convene a proceeding to consider whether current mechanisms are adequate to incent generation construction in New Jersey. The BPU has commenced such a proceeding to consider whether there is a need for additional procurements of up to 1,600 MW of new generation. Power and PSE&G are participating in this proceeding, which calls for recommendations to be made to the BPU by the end of 2011.

The SOCA requires that the generator bid in and clear the PJM RPM base residual auction in each year of the SOCA term. The SOCA provides for each New Jersey EDC 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. In April 2011, the Federal Energy Regulatory Commission (FERC) issued an order making effective changes to the PJM Tariff that would require new generation to clear in the RPM at competitive prices which would mitigate the impacts of the subsidized SOCA pricing upon RPM auction prices. This order has been challenged on rehearing. In addition, FERC convened a technical conference on July 29, 2011 to consider whether resources that engage in self-supply should be exempt from such requirements.

The various court challenges which we and other parties made relating to LCAPP legislation are currently pending.

- The United States Environmental Protection Agency (EPA) published a proposed rule in April 2011 related to 316(b) Clean Water Act requirements. The proposed rule would establish a separate marine life entrainment mortality standard as well as new impingement mortality standards for certain existing cooling water intake structures. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take or the effect, if any, that they may have on our future capital requirements, financial condition or results of operations which could be material. If the rule were to be adopted as proposed, the impact would be material since the majority of our electric generating facilities would be affected as they employ once-through cooling utilizing tidal river and tidal waters.

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On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR). CSAPR limits power plant emissions in 27 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions will be governed by this rule beginning on January 1, 2012 for SO_2 and annual NOx and May 1, 2012 for Ozone season NOx . Certain states will be required to make additional SO_2 reductions in 2014.

We continue to evaluate the impact of this rule on us due to many of the uncertainties that still exist regarding implementation; however, considering the significant investments we have made over the past several years to lower the SO_2 and NOx emissions of our fossil plants in the states affected by CSAPR (New Jersey, New York and Pennsylvania), we do not foresee the need to make any significant capital expenditures to our generation fleet to comply with the regulation. As such, we believe this rule will not have a material impact to our financial condition or operations.

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

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

In July 2011, the NRC task force submitted a report on the first 90 days of its nuclear power plant review. The report contained various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. These recommendations include proposed requirements for upgraded seismic and flooding protection, strengthening plants ability to deal with prolonged loss of power and development of emergency plans for events involving multiple reactors. The NRC Chairman has indicated that the NRC should provide clear direction within 90 days which could include interim steps on the issues identified or commencing the process for longer-term rulemakings.

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

During 2011, the SEC and the Commodity Futures Trading Commission (CFTC) are continuing efforts to implement new rules to enact stricter regulation over swaps and derivatives. CFTC has issued Notices of Proposed Rulemakings (NOPRs) on many of the key issues. We cannot assess the exact scope of the new rules until they are issued by the SEC and CFTC. We will carefully monitor these new rules as they are developed to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

In June, the BPU issued a new draft Energy Master Plan (EMP). We are currently analyzing the potential impacts of the draft EMP on our businesses. Our initial assessment is that if the EMP were finalized with the same provisions as drafted, it is generally favorable to our utility business direction, supportive of solar, nuclear power and off-shore wind development, but represents a serious threat to the PJM competitive electric wholesale market in that as a matter of policy it directs the BPU to subsidize new natural gas fired combined cycle generation in an effort to suppress wholesale market prices. The final EMP is expected to be issued later this year, following BPU hearings, in which we intend to participate.

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

Operational Excellence

Our generating stations continued to operate well in 2011. Generation volumes for the first six months of 2011 were approximately 4% lower than in the first half of 2010, primarily at our coal facilities, due to reduced demands.

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

Financial Strength

Our cash from operations has remained strong. During the first six months of 2011, we made approximately $1 billion in capital expenditures, paid dividends of $347 million and made our entire planned pension contributions for the year 2011 of $415 million. Cash from operations for the year has and is expected to continue to benefit from two tax provisions enacted in 2010 which are expected to generate a total of approximately $800 million of cash benefits for us through accelerated depreciation, most of which is expected to be realized in 2011. See Note 13. Income Taxes for additional information. These funds, combined with proceeds from the sales of our Texas facilities, will be used to support our anticipated capital expenditures and dividend payments for the year.

In April 2011, PSEG, Power and PSE&G entered into new 5-year credit agreements resulting in an increase of $650 million in Power s total credit capacity and increasing our total credit capacity to $4.3 billion.

Disciplined Investment

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

During 2011, we reached agreements to sell our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions for a total of approximately $687 million. In March 2011, we completed the sale of one plant for $352 million. The sale of the second plant closed in July 2011 for approximately $335 million. See Note 4. Discontinued Operations and Dispositions for further information.

We are continuing to pursue obtaining the necessary regulatory approvals for the Susquehanna-Roseland transmission project but have incurred delays in obtaining environmental approvals which have resulted in a delay to the project implementation date. The estimated cost of construction is up to $750 million for this project. In October 2010, the PJM Board approved the North East Grid project, specifically a 230 kV project running from Roseland to Hudson. This project has an expected

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in-service date of June 2015 with an estimated cost of construction of up to $880 million. We have also filed for BPU approval of the North-Central Reliability project, a 230 kV upgrade project located in the northern and central portions of New Jersey with an estimated cost of construction of approximately $336 million. The North-Central Reliability project has an expected in-service date of June 2014. Delays in the construction schedules of these projects could impact the timing of expected transmission revenues.

In April 2011, we filed a petition with FERC seeking incentive rates with an effective date of June 14, 2011 for five 230 kV transmission projects. In June 2011, FERC granted incentive rates for three of these 230 kV projects, with a total capital investment of approximately $1.0 billion, representing approximately 80% of our request. The incentive rates include recovery for Construction Work in Progress and 100% recovery of prudently-incurred abandonment costs. See Item 5. Other Information, Federal Regulation, Transmission Regulation Transmission Expansion for further information.

Our utility has made additional investments in solar initiatives. Under our solar loan program we have provided a total of $93 million in loans for 317 projects as of June 30, 2011, representing 26 MW to date. Under our Solar 4 All program we have made total program expenditures of approximately $278 million as of June 30, 2011. Over 21 MW of solar panels have been installed on distribution poles and another 23 MW representing 15 projects have been placed into service. Additional projects are in various stages of negotiation and development. Our total anticipated expenditures to develop all approved 80 MW is approximately $465 million. The BPU has commenced a generic stakeholder proceeding, however, to examine whether utility rate-based solar programs should be modified, expanded or terminated in the future.

We made additional expenditures under our Capital Economic Stimulus and Energy Efficiency Economic Stimulus programs. As of June 30, 2011, total capital expenditures since inception of these projects were $701 million and $118 million, respectively. In July, the BPU approved extensions to both of these programs which provide for approximately $273 million in accelerated capital investments in our electric and gas infrastructure through 2012 and $95 million of additional capital expenditures for energy efficiency programs. In conjunction with the extension of the Capital Economic Stimulus programs, we agreed to additional electric and gas base spending of approximately $96 million during the program.

We continued various construction activities at Power, including a steam path retrofit and extended power uprate at Peach Bottom and construction of new gas fired peaking units at Kearny and in Connecticut (see Note 8. Commitments and Contingent Liabilities for additional information). This additional capacity at Kearny was bid into and has cleared the RPM capacity auction, and the additional capacity in Connecticut is subject to a contract with a Connecticut utility.

We are continuing our efforts to obtain an Early Site Permit for a new nuclear generating station to be located at the current site of Salem and Hope Creek stations.

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

Our leveraged lease investments face risks with regard to the creditworthiness of the various counterparties. Relative to the assets subject to lease to Dynegy Inc. (Dynegy), our lease collateral includes a guarantee from Dynegy Holdings Incorporated (DHI), a subsidiary of Dynegy Inc. DHI holds other generation assets that we believe were intended to support DHI s guarantee obligations to us. Recently, management of Dynegy announced a plan to reorganize and recapitalize the legal entity structure for their generation assets. Under their plan, they would transfer substantially all of their coal and natural gas-fired generation assets, other than the Roseton and Danskammer facilities, to new bankruptcy remote subsidiaries. Following the announcement of this plan, in July 2011, Moody s lowered certain ratings of Dynegy and DHI.

Subsidiaries of Energy Holdings that hold our lessor interests filed a lawsuit in Delaware Chancery Court against DHI to halt DHI s proposed transfer of assets to two bankruptcy remote entities as part of a reorganization. In our complaint, we alleged that we believe that DHI s proposed transfers violate DHI s obligations under its Roseton and Danskammer guarantees. Our request for a temporary restraining order was denied on July 29, 2011 and we have since sought review with the Delaware Supreme Court.

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No assurances can be given regarding the outcome of this litigation against Dynegy. As of June 30, 2011, our gross investment in these leases was $264 million. A foreclosure event could result in an aggregate after tax charge between $170 million and $180 million. As part of this potential foreclosure event, PSEG could be required to pay approximately $100 million to satisfy income tax obligations. This potential cash tax obligation is fully reflected in the overall estimate of the aggregate after tax charge.

RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and six months ended June 30, 2011 and 2010 are presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
Earnings (Losses)	**2011**	**2010**	**2011**	**2010**
		Millions		
Power	$ 205	$ 202	$ 502	$ 573
PSE&G	105	3	268	121
Energy Holdings	5	12	2	19
Other (A)	5	5	10	7
PSEG Income from Continuing Operations	320	222	782	720
PSEG Income (Loss) from Discontinued Operations (B)	3	2	67	(5)
PSEG Net Income	**$ 323**	**$ 224**	**$ 849**	**$ 715**

	Three Months Ended June 30,		Six Months Ended June 30,	
Earnings Per Share (Diluted)	**2011**	**2010**	**2011**	**2010**
PSEG Income from Continuing Operations	**$ 0.63**	**$ 0.44**	**$ 1.54**	**$ 1.42**
Income (Loss) from Discontinued Operations	0.00	0.00	0.13	(0.01)
PSEG Net Income	**$ 0.63**	**$ 0.44**	**$ 1.67**	**$ 1.41**

(A) Other primarily includes parent company interest and financing costs, donations and certain administrative and general expenses.

(B) See Note 4. Discontinued Operations and Dispositions.

Our results include the realized gains, losses and earnings on Power s Nuclear Decommissioning Trust (NDT) funds and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT funds which are recorded in Other Income and Deductions. This also includes credit-related impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power s nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation expense related to the ARO asset.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity.

The quarter-over-quarter and six month-over-six month variances in our Income from Continuing Operations include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	Millions, after tax			
NDT Fund Income (Expense)	$ 15	$ 10	$ 42	$ 20
Non-Trading Mark-to-Market Gains (Losses)	$ 4	$ (37)	$ 8	$ 12

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In addition to the changes in NDT and MTM, our increase in Income from Continuing Operations for the three months ended June 30, 2011 was driven primarily by:

- the absence of a $122 million charge recorded in June 2010 related to our agreement to refund previous Market Transition Charge (MTC) collections,
- higher transmission and distribution rates,
- lower Operations and Maintenance costs reflecting lower pension and other postretirement employee benefit (OPEB) costs and the absence of a 2010 write-off associated with the new customer accounting system, and
- reduced losses on certain wholesale electric energy supply contracts,
- partially offset by lower volumes and pricing on our BGS contracts, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

Our increase in Income from Continuing Operations for the six months ended June 30, 2011 was driven primarily by:

- the absence of a $122 million charge related to our agreement to refund previous MTC collections,
- higher transmission and distribution rates, and
- lower Operations and Maintenance costs reflecting the same items discussed above for the three month period and lower storm restoration costs,
- partially offset by lower volumes and pricing on our BGS contracts, and
- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 17. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below.

	Three Months Ended June 30,		Increase/ (Decrease) 2011 vs 2010		Six Months Ended June 30,		Increase/ (Decrease) 2011 vs 2010	
	2011	2010			2011	2010		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,469	$ 2,361	$ 108	5	$ 5,823	$ 5,934	$ (111)	(2)
Energy Costs	1,010	1,072	(62)	(6)	2,573	2,760	(187)	(7)
Operation and Maintenance	575	601	(26)	(4)	1,226	1,271	(45)	(4)
Depreciation and Amortization	235	229	6	3	476	456	20	4
Income from Equity Method Investments	4	5	(1)	(20)	7	8	(1)	(13)
Other Income and (Deductions)	40	35	5	14	103	62	41	66
Other-Than-Temporary Impairments	1	5	(4)	(80)	5	6	(1)	(17)
Interest Expense	117	120	(3)	(3)	244	236	8	3
Income Tax Expense	227	124	103	83	556	485	71	15
Income (Loss) from Discontinued Operations	3	2	1	50	67	(5)	72	NA

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Power

	Three Months Ended June 30, 2011	2010	Increase/ (Decrease) 2011 vs 2010	Six Months Ended June 30, 2011	2010	Increase/ (Decrease) 2011 vs 2010
			Millions			
Income from Continuing Operations	$ 205	$ 202	$ 3	$ 502	$ 573	$ (71)
Income (Loss) from Discontinued Operations, net of tax	$ 3	$ 2	$ 1	$ 67	$ (5)	$ 72
Net Income	$ 208	$ 204	$ 4	$ 569	$ 568	$ 1

For the three months ended June 30, 2011 the primary reasons for the $3 million increase in Income from Continuing Operations were

- improved results related to our MTM activity, and
- reduced losses on certain wholesale electric energy supply contracts,
- partially offset by lower average pricing and volumes for electricity sold under our BGS contracts,
- higher Operation and Maintenance expense related to outage work at certain of our fossil plants, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

For the six months ended June 30, 2011 the primary reasons for the $71 million decrease in Income from Continuing Operations were

- lower average pricing and volumes for electricity sold under our BGS contracts,
- higher Operation and Maintenance expense related to refurbishments at certain of our fossil plants, and
- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants,
- partially offset by favorable amounts related to our NDT activity.

The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase/(Decrease) 2011 vs 2010		Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase /(Decrease) 2011 vs 2010	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,285	$ 1,264	$ 21	2	$ 3,252	$ 3,460	$ (208)	(6)
Energy Costs	603	612	(9)	(1)	1,738	1,863	(125)	(7)
Operation and Maintenance	271	260	11	4	548	511	37	7
Depreciation and Amortization	56	44	12	27	110	87	23	26
Other Income (Deductions)	35	30	5	17	93	55	38	69
Other-Than-Temporary Impairments	1	5	(4)	(80)	3	6	(3)	(50)
Interest Expense	41	42	(1)	(2)	92	82	10	12
Income Tax Expense	143	129	14	11	352	393	(41)	(10)
Income (Loss) from Discontinued Operations	3	2	1	50	67	(5)	72	N/A

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For the three months ended June 30, 2011 as compared to 2010

Operating Revenues increased $21 million due to

Trading Revenues increased $15 million due primarily to lower net losses on certain electric energy supply contracts in 2011.

Generation Revenues increased $8 million due primarily to

higher net revenues of $65 million resulting principally from less unfavorable net results from financial hedging transactions in 2011 in the PJM, NY and New England (NE) power pools, partially offset by lower generation volumes sold in these power pools, and

an increase of $40 million from new wholesale load contracts in PJM and the NE regions commencing in January 2011 and April 2011, respectively,

partially offset by a net decrease of $81 million due to lower average pricing and lower volumes sold under our BGS contracts, and

decreases of $11 million due to lower capacity payments from PJM resulting from lower prices and $4 million due to lower auction revenue rights rates.

Gas Supply Revenues decreased $2 million due primarily to

a net decrease of $4 million due to lower sales volumes at higher average prices to third party customers,

partially offset by a net increase of $2 million in sales under the BGSS contract, substantially comprised of increased volumes of sales due to cooler average temperatures in April 2011, substantially offset by lower average gas sales prices in 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases for generation as well as purchased energy in the market, and gas purchases to meet Power s obligation under its BGSS contract with PSE&G. Energy Costs decreased by $9 million entirely due to

Gas costs, principally related to Power s obligations under the BGSS contract, reflecting lower average gas inventory costs partially offset by higher demand due to cooler average temperatures in April 2011.

Operation and Maintenance increased $11 million due primarily to

a $7 million net increase due largely to higher outage costs at our coal-fired Keystone facility in Pennsylvania, and our gas-fired Bergen and coal-fired Mercer facilities in New Jersey as well as baghouse filter replacement costs at Mercer, and

an increase of $4 million in materials and contract labor for refurbishment projects related to the cooling, circulation and transfer of water at our Salem nuclear facilities in 2011.

Depreciation and Amortization increased $12 million due primarily to a $9 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and

a $3 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net increase of $5 million was due primarily to higher net realized gains on the NDT funds.

Other-Than-Temporary Impairments decreased $4 million due to the absence in 2011 of $4 million of impairments on the NDT Funds recorded in 2010.

Interest Expense experienced no material change.

Income Tax Expense increased $14 million in 2011 due primarily to higher pre-tax income and the absence of tax benefits recorded in the second quarter of 2010 associated with manufacturer s deductions under the American Jobs Creation Act of 2004.

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Income (Loss) from Discontinued Operations

In January 2011, we reached agreement to sell our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million at an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of approximately $335 million at an after-tax gain of approximately $25 million. The sale of the second plant will be reflected in Power s Condensed Consolidated Financial Statements for the third quarter of 2011. The results of operations for both plants are included in this category.

See Note 4. Discontinued Operations and Dispositions for additional information.

For the six months ended June 30, 2011 as compared to 2010

Operating Revenues decreased $208 million due to

Generation Revenues decreased $110 million due primarily to

- a net decrease of $140 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts,
- lower net revenues of $32 million resulting principally from less favorable results from financial hedging transactions in the various power pools and lower generation volumes sold in the PJM, NE and NY power pools, and
- decreases of $6 million due to lower capacity payments from PJM resulting from lower prices and $11 million due to lower auction revenue rights rates,
- partially offset by an increase of $80 million from new wholesale load contracts in PJM and the NE regions commencing in January 2011 and April 2011, respectively,

Gas Supply Revenues decreased $86 million due primarily to

- a net decrease of $106 million in sales under the BGSS contract, substantially comprised of lower average gas sales prices partially mitigated by increased volumes of sales due to colder average temperatures during the 2011 winter heating season,
- partially offset by a net increase of $20 million due to higher sales volumes at lower average prices to third party customers.

Trading Revenues decreased $12 million due primarily to higher net losses in 2011 on certain electric energy supply contracts.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases for generation as well as purchased energy in the market, and gas purchases to meet Power s obligation under its BGSS contract with PSE&G. Energy Costs decreased $125 million due to

- **Gas costs** decreased $94 million, principally related to Power s obligations under the BGSS contract, reflecting lower average gas inventory costs partially offset by higher demand due to colder average temperatures in the winter heating season in 2011, as well as higher demand by third party customers.

Generation costs decreased $31 million due primarily to $72 million of lower net fossil fuel costs, primarily reflecting the utilization of lower volumes of coal and natural gas and the lower cost of natural gas, $35 million of lower net congestion charges incurred in 2011 from PJM and a $13 million decrease due to lower impairment charges in 2011 related to excess SO_2 emissions allowances. These decreases were partly offset by an increase of $80 million in spot energy purchases in 2011 in the NE and PJM power pools in order to meet higher load contract demand in 2011, a $6 million increase in nuclear fuel costs and $6 million due to higher PJM transmission expense in 2011 as a result of new PJM load and a higher BGS contract rate.

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Operation and Maintenance increased $37 million due primarily to

- a $29 million net increase due largely to hot gas path inspection outage costs at our gas-fired Bethlehem Energy and Linden facilities in New York and New Jersey, respectively, as well as to higher outage costs at our coal-fired Keystone facility in Pennsylvania, our gas-fired Bergen and our coal-fired Mercer facilities in New Jersey and baghouse filter replacement costs at Mercer partially offset by refunds of easement costs related to certain of our fossil plants, and

- an increase of $8 million due to refurbishment projects at our Peach Bottom and Salem nuclear facilities.

Depreciation and Amortization increased $23 million due primarily to

- a $19 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and

- a $4 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net increase of $38 million was due primarily to $42 million of higher net realized gains on the NDT funds mainly resulting from the liquidation of an underperforming fund in March 2011 and a rebalancing to move toward our target asset allocation.

Other-Than-Temporary Impairments decreased $3 million due to higher impairments of $4 million on the NDT Funds in 2010 and an impairment of $1 million on the Rabbi Trust Fund in 2011.

Interest Expense increased $10 million due primarily to

- lower capitalized interest of $24 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson fossil stations,

- partially offset by lower interest expense of $12 million due to the redemption of $606 million of 7.75% Senior Notes in early April 2011 and lower amortization of long-term debt issuance costs of $3 million.

Income Tax Expense decreased $41 million in 2011 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

As discussed above, we sold our two Texas plants in March 2011 and July 2011, respectively. The results of operations for both plants, including the after-tax gain of $54 million from the March 2011 sale, are included in this category.

See Note 4. Discontinued Operations and Dispositions for additional information.

PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2011	**2010**	**2011 vs 2010**	**2011**	**2010**	**2011 vs 2010**

			Millions			
Income from Continuing Operations	$ 105	$ 3	$ 102	$ 268	$ 121	$ 147
Net Income	$ 105	$ 3	$ 102	$ 268	$ 121	$ 147

For the three months ended June 30, 2011, the primary reasons for the $102 million increase in Income from Continuing Operations were

the absence of a $122 million charge recorded in June 2010 related to the refund of previous MTC collections,

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

lower Operation and Maintenance expense.

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For the six months ended June 30, 2011, the primary reasons for the $147 million increase in Income from Continuing Operations were

- the absence of a $122 million charge recorded in June 2010 related to the refund of previous MTC collections,
- higher annualized base rates for electric and gas delivery as well as transmission,
- higher gas delivery volumes, and
- lower Operation and Maintenance expense.

The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended June 30,		Increase/ (Decrease) 2011 vs 2010		Six Months Ended June 30,		Increase/ (Decrease) 2011 vs 2010	
	2011	2010			2011	2010		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,571	$ 1,536	$ 35	2	$ 3,877	$ 3,980	$ (103)	(3)
Energy Costs	815	917	(102)	(11)	2,181	2,457	(276)	(11)
Operation and Maintenance	304	343	(39)	(11)	672	757	(85)	(11)
Depreciation and Amortization	172	177	(5)	(3)	351	354	(3)	(1)
Other Income (Deductions)	4	3	1	33	8	7	1	14
Other-Than-Temporary Impairments	0	0	0	0	1	0	1	N/A
Interest Expense	78	80	(2)	(3)	157	157	0	0
Income Tax Expense (Benefit)	73	(9)	82	N/A	184	71	113	N/A

For the three months ended June 30, 2011 as compared to 2010

Operating Revenues increased $35 million due primarily to

Clause Revenues increased $111 million due primarily to the absence of a $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years and higher Societal Benefits Charge (SBC) and Margin Adjustment Clause (MAC) of $13 million, partially offset by lower Securitization Transition Charge (STC) revenues of $24 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Delivery Revenues increased $24 million due primarily to an increase in prices for electric and gas distribution and transmission.

- Gas distribution revenues were up $19 million due primarily to higher sales volumes of $10 million, higher Weather Normalization Clause revenue of $7 million and the impact of the prior year July base rate increase of $5 million, partially offset by lower capital stimulus revenue of $3 million.
- Transmission revenues were up $9 million due primarily to prior year net rate increases.

Electric distribution revenues were down $4 million due primarily to lower sales volumes of $9 million and lower stimulus revenue of $4 million, partially offset by the impact of the prior year June base rate increases of $9 million.

Other Operating Revenues increased $2 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Commodity Revenue decreased $102 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS.

Electric revenues decreased $86 million due primarily to $139 million in lower BGS revenues, partially offset by $53 million in higher revenues from the sale of Non-Utility Generation (NUG) energy and collections of non-utility generation charges (NGC) due primarily to higher prices. BGS sales were down 18% due primarily to large customer migration to third party suppliers (TPS); in contrast delivery sales were down only 3% due to weather.

Gas revenues decreased $16 million due to lower BGSS prices of $37 million, partially offset by higher BGSS volumes of $21 million due to weather. The average price of gas was 19% lower in 2011 than in 2010.

Energy Costs decreased $102 million. This is entirely offset by Commodity Revenue. Details are as follows:

Electric costs decreased $86 million due to $113 million or 16% in lower BGS and NUG volumes due to large customer migration to TPS and NUG operations and $1 million of lower BGS and NUG prices, partially offset by $28 million for increased deferred cost recovery.

Gas costs decreased $16 million due to $37 million or 19% in lower prices, partially offset by $21 million or 11% in higher sales volumes due primarily to weather.

Operation and Maintenance decreased $39 million due primarily to

$21 million of lower net deferred expenses associated with SBC, Regional Greenhouse Gas Initiative (RGGI) and Stimulus clauses,

a $17 million decrease in pension and OPEB expenses, and

the absence of $16 million in expenses relating to 2010 rate case disallowances,

partially offset by a $14 million increase in bad debt expense.

Depreciation and Amortization decreased $5 million due primarily to

a decrease of $15 million for amortization of Regulatory Assets,

partially offset by an increase of $8 million for additional plant in service, and

an increase of $2 million in software amortization,

Other Income and (Deductions) experienced no material change.

Other-Than-Temporary Impairments experienced no change.

Interest Expense decreased $2 million due primarily to lower average debt balances.

Income Tax Expense increased $82 million due primarily to higher pre-tax income.

For the six months ended June 30, 2011 as compared to 2010

Operating Revenues decreased $103 million due primarily to

Commodity Revenue decreased $276 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS.

Gas revenues decreased $154 million due to lower BGSS prices of $201 million, partially offset by higher BGSS volumes of $47 million due to colder weather. The average price of gas was 20% lower in 2011 than in 2010.

Electric revenues decreased $122 million due primarily to $194 million in lower BGS revenues, partially offset by $72 million in higher revenues from the sale of NUG energy and collections of NGC due primarily to higher prices. BGS sales were down 15% due primarily to large customer migration to TPS; in contrast delivery sales were down by only 2% due to weather.

Clause Revenues increased $116 million due primarily to the absence of $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years, and higher SBC and MAC

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of $37 million, partially offset by lower STC revenues of $43 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Delivery Revenues increased $52 million due primarily to an increase in prices for electric and gas distribution and transmission.

- Gas distribution revenues were up $35 million due primarily to higher sales volumes of $26 million, the impact of the prior year July base rate increase of $16 million and higher Weather Normalization Clause revenue of $3 million, partially offset by lower capital stimulus revenue of $10 million.

- Transmission revenues were up $16 million due primarily to net rate increases.

- Electric distribution revenues were up $1 million due primarily to the impact of the prior year June base rate increases of $18 million, partially offset by lower sales volumes of $9 million and lower stimulus revenue of $8 million.

Other Operating Revenues increased $5 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Energy Costs decreased $276 million. This is entirely offset by Commodity Revenue. Details are as follows:

- Gas costs decreased $154 million due to $201 million or 20% in lower prices, partially offset by $47 million or 5% in higher sales volumes due primarily to weather.

- Electric costs decreased $122 million due to $201 million or 14% in lower BGS and NUG volumes due to large customer migration to TPS and NUG operations, partially offset by $69 million for increased deferred cost recovery and $10 million of higher BGS and NUG prices.

Operation and Maintenance decreased $85 million due to

- $35 million of lower net deferred expenses associated with SBC, RGGI and Stimulus clauses,

- a $30 million decrease in pension and OPEB expenses,

- the absence of $16 million in expenses relating to 2010 rate case disallowances,

- a $14 million reduction in storm restoration work, and

- a $4 million decrease in other operating expenses, primarily incentive payments, partially offset by a $14 million increase in bad debt expense.

Depreciation and Amortization decreased $3 million due primarily to

a decrease of $23 million for amortization of Regulatory Assets,

partially offset by an increase of $15 million for additional plant in service, and

an increase of $4 million in software amortization.

Other Income and (Deductions) experienced no material change.

Other-Than-Temporary Impairments experienced no material change.

Income Tax Expense increased $113 million due primarily to higher pre-tax income.

Energy Holdings

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2011	2010	2011 vs 2010	2011	2010	2011 vs 2010
			Millions			
Income from Continuing Operations	$ 5	$ 12	$ (7)	$ 2	$ 19	$ (17)
Net Income	$ 5	$ 12	$ (7)	$ 2	$ 19	$ (17)

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For the three months and six months ended June 30, 2011, the primary reason for the $7 million and $17 million decreases in Income from Continuing Operations was the absence of tax benefits related to two projects entering service in 2010 and lower lease related gains.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

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

For the six months ended June 30, 2011, our operating cash flow increased $875 million as compared to the same period in 2010. The net change was due primarily to net changes from Power, PSE&G and Energy Holdings, as discussed below.

Power

Power s operating cash flow increased $392 million from $754 million to $1,146 million for the six months ended June 30, 2011, as compared to the same period in 2010, primarily resulting from

an increase of $335 million due to lower tax payments primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Note 13. Income Taxes for additional information), and

an increase of $180 million due to higher collections of accounts receivable,

partially offset by a decrease of $91 million due to higher payments of counterparty payables.

PSE&G

PSE&G s operating cash flow increased $300 million from $(21) million to $279 million for the six months ended June 30, 2011, as compared to the same period in 2010, due primarily to higher earnings for the period combined with

an increase of $126 million due to lower tax payments primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Note 13. Income Taxes for additional information), and

an increase of $114 million due to higher collections of customer receivables.

Energy Holdings

Energy Holdings operating cash flow improved $165 million for the six months ended June 30, 2011, as compared to the same period in 2010, primarily due to lower tax payments in 2011 related to lease sale activity.

Short-Term Liquidity

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

The commitments under our credit facilities are provided by a diverse bank group. As of June 30, 2011, no single institution represented more than 8% of the total commitments in our credit facilities.

As of June 30, 2011, our total credit capacity was in excess of our anticipated maximum liquidity requirements through the end of 2011.

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Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries liquidity needs. Our total credit facilities and available liquidity as of June 30, 2011 were as follows:

Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	As of June 30, 2011				
		Millions			
PSEG					
5-year Credit Facility (A)	$ 500	$ 14(C)	$ 486	Dec 2012	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility	500	0	500	Apr 2016	Commercial Paper (CP) Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 14**	**$ 986**		
Power					
5-year Credit Facility (B)	$ 1,600	$ 170(C)	$ 1,430	Dec 2012	Funding/Letters of Credit
5-year Credit Facility	1,000	0	1,000	Apr 2016	Funding/Letters of Credit
Bilateral Credit Facility	100	100(C)	0	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 270**	**$ 2,430**		
PSE&G					
5-year Credit Facility	$ 600	$ 298	$ 302	Apr 2016	Commercial Paper (CP) Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 298**	**$ 302**		
Total	**$ 4,300**		**$ 3,718**		

(A) In December 2011, this facility will be reduced by $23 million.

(B) In December 2011, this facility will be reduced by $75 million.

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

On April 15, 2011, PSEG, Power and PSE&G entered into new 5-year credit agreements in the amounts of $500 million, $1 billion and $600 million, respectively. These new agreements will expire in April 2016. Concurrently, PSEG reduced its existing $1 billion credit facility to $500 million, Power terminated its existing $350 million credit facility, and PSE&G terminated its existing $600 million credit facility. As a result of these changes, Power s total credit capacity increased by $650 million which increased our total credit capacity to $4.3 billion.

Long-Term Debt Financing

For a discussion of our long-term debt transactions during 2011, see Note 9. Changes in Capitalization.

Common Stock Dividends

For information related to cash dividends on our common stock, see Note 15. Earnings Per Share.

We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in

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their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies ratings. The ratings should not be construed as an indication to buy, hold or sell any security. In April 2011, S&P published an updated credit opinion which left the ratings for PSEG, Power and PSE&G unchanged and improved their outlooks to positive from stable. In May 2011, Moody s affirmed its ratings for PSEG, Power and PSE&G. PSE&G s outlook was improved to positive from stable while the outlooks at PSEG and Power remain at stable. In August 2011, Fitch affirmed its ratings for PSEG, Power and PSE&G and kept all outlooks at stable.

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

(A) Moody s ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

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

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected construction and investment amounts for the years 2011 through 2013 have been revised subsequent to the Annual Report on Form 10-K for the year ended December 31, 2010. The revised amounts reflect an increase of approximately $670 million for PSE&G, due primarily to extensions to the Capital and Energy Efficiency Capital Stimulus Programs, which were approved by the BPU in July, and revisions to our anticipated spend for various transmission projects. In addition, we have removed $530 million of discretionary expenditures for non-utility renewables from our projections. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders. The current projected construction and investment expenditures, excluding nuclear fuel purchases, are presented in the table below. These amounts are subject to change, based on various factors.

	2011	2012	2013
		Millions	
Power:			
Baseline Maintenance	$ 190	$ 235	$ 155
Environmental / Regulatory	95	65	85
Fossil Growth Opportunities	265	65	0
Nuclear Expansion	120	120	100
Total Power	**$ 670**	**$ 485**	**$ 340**
PSE&G:			
Transmission			
Reliability Enhancements	$ 565	$ 765	$ 1,130
Facility Replacement	120	180	145
Support Facilities	5	5	5
Distribution			
Support Facilities	40	40	40
New Business	120	130	140
Reliability Enhancements	135	155	70
Facility Replacement	270	285	140
Environmental / Regulatory	35	50	35
Renewables / EMP	330	235	75
Total PSE&G	**$ 1,620**	**$ 1,845**	**$ 1,780**
Other	45	40	25
Total PSEG	**$ 2,335**	**$ 2,370**	**$ 2,145**

Power

During the six months ended June 30, 2011, Power made $283 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $40 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear. For additional information regarding current projects, see Note 8. Commitments and Contingent Liabilities.

PSE&G

During the six months ended June 30, 2011, PSE&G made $697 million of capital expenditures, including $674 million of investment in plant, primarily for reliability of transmission and distribution systems and $23 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $25 million, which are included in operating cash flows.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Commodity Contracts

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

Value-at-Risk (VaR) Models

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

Non-trading MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The non-trading MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities. The MTM derivatives that are not hedges are included in the trading VaR.

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

As of June 30, 2011, there was no trading VaR. As of December 31, 2010, trading VaR was $1 million.

For the Three Months Ended June 30, 2011	**Trading VaR**	**Non-Trading MTM VaR**	
	Millions		
95% Confidence level,			
Loss could exceed VaR one day in 20 days			
Period End	$ 0	$	11
Average for the Period	$ 1	$	9
High	$ 2	$	19
Low	$ 0	$	5
99.5% Confidence level,			
Loss could exceed VaR one day in 200 days			
Period End	$ 0	$	18
Average for the Period	$ 1	$	14
High	$ 3	$	30
Low	$ 0	$	8

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act) that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer and Chief Financial Officer of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the Chief Financial Officer and Chief Executive Officer of each respective company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2011 that have materially affected, or are reasonably likely to materially affect, each registrant s internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. In addition, both PSE&G and Power have filed appeals of the March 2011 BPU order approving the SOCAs to the New Jersey Superior Court Appellate Division. For information regarding material legal proceedings, including updates to information reported under Item 3 of Part I of the 2010 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

Certain information reported under the 2010 Annual Report on Form 10-K and Quarterly Reports on Form 10-Q for the quarter ended March 31, 2011 are updated below. References are to the related pages on the Form 10-K or form 10-Q as printed and distributed.

Long-Term Capacity Agreement Pilot Program (LCAPP)

December 31, 2010 Form 10-K page 47 and March 31, 2011 Form 10-Q, page 66. In an attempt to stimulate the development of new generation capacity in New Jersey through a subsidized rate mechanism, New Jersey enacted LCAPP directing the BPU to conduct a process to procure and subsidize up to 2,000 megawatts of 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 the LCAPP Act under the Supremacy and Commerce clauses of the United States Constitution. The complaint seeks declaratory and injunctive relief. The proceeding is now in the discovery phase. 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, and FERC so acted in an April 2011 order, which is now subject to rehearing. For additional information, see Item 5. Other Information.

Electric Discount and Energy Competition Act (Competition Act)

December 31, 2010 Form 10-K page 48 and March 31, 2011 Form 10-Q, page 66. 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 October 2007, the Court granted PSE&G motion to dismiss the amended Complaint and 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. In April 2011, the BPU issued a written order memorializing this decision. In June 2011, the plaintiff/petitioner filed a notice of appeal with the New Jersey Appellate Division.

Con Edison (Con Ed)

December 31, 2010 Form 10-K page 48 and March 31, 2011 Form 10-Q, page 66. 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

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

ITEM 1A. RISK FACTORS

The Risk Factor shown below is to be added to those disclosed in Part I Item 1A of our 2010 Annual Reports on Form 10-K and Part II Item 1A of our March 31, 2011 Quarterly Reports on Form 10-Q.

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

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

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2011:

Three Months Ended June 30, 2011	Total Number of Shares Purchased	Average Price Paid per Share
April 1-April 30	0	$ 0
May 1-May 31	292,193	$ 33.65
June 1-June 30	28,765	$ 33.12

ITEM 5. OTHER INFORMATION

Certain information reported under the 2010 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2011 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2010 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2011. References are to the related pages on the Form 10-K or 10-Q as printed and distributed.

EMPLOYEE RELATIONS

December 31, 2010 Form 10-K page 17 and March 31, 2011 Form 10-Q, page 67. One of the collective bargaining agreements at PSE&G was set to expire on April 30, 2011. Negotiations continued through May 2011 when a new collective bargaining agreement was approved. The new agreement will expire in April 2014.

FEDERAL REGULATION

FERC

Regulation of Wholesale Sales Generation/Market Issues/Market Design Issues

December 31, 2010 Form 10-K page 18. Market Power PSE&G, PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC each filed for an update of their respective market-based rate (MBR) authority in December 2010. On June 29, 2011, these companies were granted continued MBR authority from FERC.

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December 31, 2010 Form 10-K page 18. 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. In November 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, we filed at FERC for extension of the RMR agreement for Hudson Unit 1 through September 1, 2012. FERC granted this extension in an order issued in May 2011. In June 2011, however, Power asked PJM to re-evaluate whether the extension of the RMR contract is necessary. On August 2, 2011, PJM determined that such an extension was not needed and stated that it will be releasing the RMR contract.

Capacity Market Issues

December 31, 2010 Form 10-K page 19 and March 31, 2011 Form 10-Q, page 67. In an attempt to stimulate the development of new generation capacity in New Jersey through a subsidized rate mechanism, in January 2011, New Jersey enacted the LCAPP Act directing the BPU to conduct a process to procure and subsidize up to 2,000 megawatts of baseload or mid-merit electric power generation. In March 2011, the BPU issued a written order approving a form of agreement and selecting three generators to build a total of 1,949 MW of new combined-cycle generating facilities located in New Jersey. The BPU decision requires the New Jersey electric distribution companies, including PSE&G, to execute the BPU approved financially settled standard offer capacity agreements (SOCAs) with each of the three selected generators. The SOCA requires that the generator bid in and clear the PJM RPM base residual auction in each year of the SOCA term. The SOCA provides for the EDCs 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 Act and the BPU order provide that, once the SOCAs are executed and approved by the BPU, they will be irrevocable and the EDCs will be entitled to full rate recovery of the prudently incurred costs. In April 2011 the EDCs jointly filed a motion for reconsideration of the BPU s March order, arguing that the order violated due process and failed to comply with the LCAPP Act. In May 2011, the BPU denied the EDCs motion for reconsideration. Both PSE&G and Power subsequently filed appeals of the BPU order to the New Jersey Superior Court Appellate Division.

Each of the New Jersey EDCs, including PSE&G, executed SOCAs with the three generators in compliance with the BPU s directive, but did so under protest reserving its legal rights. In April 2011, the BPU approved the executed contracts and also announced its intent to convene a proceeding to consider whether current mechanisms are adequate to incent generation construction in New Jersey. This proceeding, in which both PSE&G and Power are participating, has commenced. In this proceeding, the BPU is examining the need for an additional procurement of generation of up to 1,600 MW. A legislative hearing has already been conducted and comments have been filed. PSE&G and Power argued in separate comments that the markets are working and that the proposed additional procurement would distort market outcomes and harm customers. The procedural schedule for this proceeding calls for recommendations to be presented to the BPU by the end of 2011.

In an effort to prevent the LCAPP Act and other similar state actions from harming competitive wholesale markets, PSEG joined a group of generators and filed a complaint at FERC in February 2011 which sought to correct a flaw in the PJM tariff that allowed for the artificial suppression of capacity prices by buy side resources. With a similar objective, also in February 2011, PJM filed with FERC to update and simplify the minimum offer price rule (MOPR). While there were some differences in the relief sought by the generator complaint and the PJM filing, both filings sought changes to the same MOPR tariff provisions for the purposes of preventing subsidized generation from artificially depressing the wholesale capacity markets. In April 2011, FERC issued an order making effective changes to the PJM Tariff that would require new generation to clear in the RPM at competitive prices which would mitigate the impacts of the subsidized SOCA pricing upon RPM auction prices. This order has been challenged by the BPU on rehearing. In addition, on July 29, 2011, the FERC held a technical conference to consider whether resources that engage in self-supply should be exempted from MOPR requirements.

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The LCAPP Act is also being challenged in court. We joined a group filing a complaint in U.S. District Court in New Jersey arguing that the legislation is unconstitutional and should be invalidated. This court action is currently in the discovery phase.

Transmission Regulation Transmission Expansion

December 31, 2010 Form 10-K page 20 and March 31, 2011 Form 10-Q, page 68. We have not received certain environmental approvals that are required for each of the Eastern and Western segments of the Susquehanna-Roseland line and believe that it is now unlikely that we will obtain these approvals until early 2013, at the earliest. The Western portion of the line also requires certain permits from the National Park Service. In May, we received a letter from the National Park Service that postpones the agency s issuance of a Record of Decision for this project until January 2013, which represents a three month delay from the previous schedule. We are currently evaluating this additional delay from the National Park Service and any resulting impact on the previously expected in- service date of June 2014 for the Eastern segment and June 2015 for the Western segment. Further delays are also possible for both portions. Delays in the construction schedule could impact the timing of expected transmission revenues.

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 $880 million (North East Grid project). 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. In April 2011, we filed a petition with FERC seeking incentive rates for five of these projects (Burlington-Camden project, North Central Reliability project, the Mickleton-Gloucester-Camden project, Middlesex Switch Rack project and Bayonne-Marion project). For each of these projects, PSE&G requested inclusion of 100% of CWIP in rate base and recovery of 100% of prudently incurred abandonment costs with an effective date of June 14, 2011. In June 2011, the FERC granted the requested incentives for three of the projects (Burlington-Camden, North Central Reliability project and Mickleton-Gloucester-Camden) with a total estimated capital investment of $1.0 billion, representing approximately 80% of our request.

Transmission Regulation Transmission Policy Developments

December 31, 2010 Form 10-K page 20. In 2010, the FERC initiated a rulemaking proceeding to evaluate whether reforms were necessary to current transmission planning and cost allocation rules to stimulate additional transmission development. The rulemaking also addressed the issue of whether the ROFR contained in FERC-approved tariffs and contracts, under which incumbent transmission companies have a ROFR to build transmission located within their respective service territories, should be eliminated. On July 21, 2011, the FERC issued a Final Rule in this proceeding. The Final Rule, among other things (i) directs regional planners such as PJM to modify their planning processes to consider transmission needs driven by public policy requirements established by state or federal laws or regulations (ii) directs regional planners to remove the ROFR from its tariffs and agreements, subject to exceptions for certain types of projects and subject to a back-stop mechanism that may permit incumbent transmission owners to step in and build transmission if third party

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developers projects are delayed (iii) requires regional planners to develop regional cost allocation methodologies consistent with certain articulated principles, including that costs be roughly commensurate with project benefits and (iv) requires regional planners in neighboring regions to have a common interregional cost allocation method for new interregional facilities. PSEG and other parties to the proceeding are expected to challenge the Final Rule on rehearing and ultimate judicial appeals are likely. An expected outcome of this Final Rule is the construction of more transmission through public policy planning and the opening up of transmission construction and ownership to third party developers and to incumbents seeking to build outside of their service territories. We cannot predict the final outcome or impact on us, however, specific implementation of the Final Rule in the various regions, including within our service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.

Commodity Futures Trading Commission (CFTC)

December 31, 2010 Form 10-K page 22 and March 31, 2011 Form 10-Q, page 69. 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).

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

- defining swaps,
- defining swap dealers and major swap participants,
- the end-user exception from clearing requirements,
- position limits,
- margin requirements,
- capital requirements, and
- reporting requirements.

Exchanges and DCOs typically require full collateralization of all transactions taking place on the exchange or DCO. Although the Dodd-Frank Act specifically recognizes a commercial end user exemption from posting additional collateral in the bilateral Over the Counter swap and derivative markets, we cannot assess the exact scope of the new rules until the SEC and CFTC issue them. 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 believe that any regulatory change that deviates from the original intent would need to be addressed by additional legislation.

Under the margin requirement NOPR, no margin would be applied to any transaction with an end-user, except for a proposal for banks that would impose a one-way margin flowing from the end-user to the bank for any transaction that exceeds a credit threshold set by the bank. Additional rules have been proposed that re-examine this end-user exemption, which could have adverse consequences upon Power.

We will carefully monitor these new rules as they are developed to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

Nuclear Regulatory Commission (NRC)

March 31, 2011 Form 10-Q, page 70. As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the NRC will be performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events

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in Japan may result in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants meet the stringent applicable design and safety specifications of the NRC.

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

In July 2011, the NRC task force submitted a report on the first 90 days of its nuclear power plant review. The report contained various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. These recommendations include proposed requirements for upgraded seismic and flooding protection, strengthening plants ability to deal with prolonged loss of power and development of emergency plans for events involving multiple reactors. The NRC Chairman has indicated that the NRC should provide clear direction within 90 days which could include interim steps on the issues identified or commencing the process for longer-term rulemakings.

STATE REGULATION

Rates

Remediation Adjustment Clause (RAC)

December 31, 2010 Form 10-K page 26 and March 31, 2011 Form 10-Q, page 70. In November 2010, we filed a RAC 18 petition with the BPU requesting an increase in electric and gas RAC rates of approximately $3 million and $1 million, respectively. In May 2011 a settlement was signed by the parties and filed with the Administrative Law Judge (ALJ) for the requested amounts. Also in May 2011 the ALJ issued an initial decision adopting the executed stipulation of the parties to the proceeding. The ALJ s Initial Decision was approved by the BPU in June 2011. New rates were effective July 1, 2011.

RGGI Recovery Charge (RRC)

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 Energy Efficiency Economic Stimulus Program, the Demand Response Program, Solar 4 All, and the Solar Loan II Program.

Energy Supply

BGSS

December 31, 2010 Form 10-K page 27 and March 31, 2011 Form 10-Q, page 70. On June 1, 2011, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $16.1 million, excluding sales and use tax, to be effective October 1, 2011. This would represent a reduction of approximately 1.1% for a typical residential gas heating customer.

Energy Policy

New Jersey Energy Master Plan (EMP)

December 31, 2010 Form 10-K page 27 and March 31, 2011 Form 10-Q, page 71. During 2010, the Governor of New Jersey directed the BPU to review the State s current EMP. In June, the BPU released a new draft EMP. We are currently analyzing the potential impacts of the draft EMP on our business. Our initial assessment is that if the EMP were finalized with the same provisions as drafted, it is generally favorable to our utility business direction, supportive of nuclear power and off-shore wind development, but represents a serious threat to the PJM competitive electric wholesale market in that as a matter of policy it directs the BPU

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to subsidize new natural gas fired combined cycle generation in an effort to suppress wholesale market prices. The final EMP is expected to be issued later this year, following BPU hearings, in which we intend to participate.

Compared to the current EMP, the new draft places a stronger emphasis on controlling and developing the in-state generation market and reducing energy costs. The draft recognizes the impact of climate change and accepts the previously set goals of a 22.5% target for the renewable portfolio standard (RPS) in 2021. It also references a goal that 70% of New Jersey s energy supplies should be from clean energy sources by 2050. To meet this goal, the draft calls for a redefinition of clean energy to include nuclear, natural gas and hydro power along with defined renewable sources and proposes a number of changes aimed at reducing the cost of achieving the 22.5% goal.

Specific program initiatives in the draft EMP include:

- implementation of LCAPP, with the continued State challenge to FERC and PJM policies on market pricing rules in the capacity market;
- support for construction of new nuclear generation;
- development of decentralized combined heat and power;
- expanded natural gas use to meet energy needs;
- re-evaluation of the costs, incentives and impact on rates of the solar renewable program;
- re-evaluation of alternative and emerging technologies, to create appropriate incentives;
- continued support for implementation of off-shore wind, without setting a specific capacity goal; and
- continued support for energy efficiency initiatives, but recognizing that the previous goal of a 32% reduction in natural gas use by 2020 is unachievable.

Solar Generic Proceeding

The BPU has commenced a generic proceeding to examine whether existing utility rate-based solar programs, including ours, should be expanded, modified or discontinued once the current programs expire or the authorized level of solar installations has been achieved. Although the current programs are not expected to be affected, the proceeding will examine the costs and benefits of all of these programs. We cannot predict the outcome of this proceeding.

Energy Efficiency Economic Stimulus Program

December 31, 2010 Form 10-K page 29. 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 June 2011, $118 million of the $166 million had been invested with the remaining $48 million fully committed. 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 July 2011, PSE&G received BPU approval to extend three subprograms (multi-family, municipal and hospital) which are currently in operation and are fully subscribed with a backlog of customer applications. PSE&G received authorization to extend the subprograms offerings under the same process, terms and conditions while receiving the ability to make approximately $95 million of additional capital expenditures.

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Capital Economic Stimulus Infrastructure Program

December 31, 2010 Form 10-K page 29 and March 31, 2011 Form 10-Q, page 71. 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 38 qualifying projects totaling $694 million. The Capital Adjustment Charge (CAC) was established to provide recovery prior to the inclusion of the investments in rates. It will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting.

We 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 our 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 and the CAC rates were adjusted accordingly, again on a provisional basis. We spent $408 million on approved infrastructure projects in 2010 and collected approximately $36 million through the CAC.

In November 2010, we made our 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. 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.

In July 2011, the BPU approved settlement agreements resolving our November 2010 annual filing to update the CAC rates and our November 2010 and February 2011 filings to extend our gas and electric Capital Stimulus programs. As part of the settlement, PSE&G agreed to an established base spending level that includes additional electric and gas spending of approximately $96 million, apart from Capital Stimulus, for 2011 through 2012 for gas and 2011 through 2013 for electric. Following the completion of the 38 qualifying projects included in PSE&G s initial Capital Stimulus program, PSE&G will make a filing to roll into rate base the initial Capital Stimulus investments not yet in base rates. Through the end of June 2011, PSE&G has spent $701 million in gas and electric Capital Stimulus investments.

Regarding the Capital Stimulus extension, the BPU also approved 24 qualifying projects totaling approximately $78 million and $195 million in expenditures for gas and electric, respectively, to be completed and placed in service by December 2012. Filings to implement rates to recover these costs will be made by November 1, 2011 and at the conclusion of the final qualifying projects.

Carbon Abatement Program

December 31, 2010 Form 10-K page 29 and March 31, 2011 Form 10-Q, page 71. 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 June 30, 2011, $29.6 million of the approved $46 million investment had been spent on energy efficiency measures.

LCAPP

See Federal Regulation Capacity Market Issues above.

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ENVIRONMENTAL MATTERS

Air Pollution Control

Clean Air Interstate Rule (CAIR), Clean Air Transport Rule (CATR) and Cross-State Air Pollution Rule (CSAPR)

December 31, 2010 Form 10-K page 31. On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR). CSAPR limits power plant emissions in 27 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions will be governed by this rule beginning on January 1, 2012 for SO2 and annual NOx and May 1, 2012 for Ozone season NOx . Certain states will be required to make additional SO2 reductions in 2014.

We continue to evaluate the impact of this rule on Power and PSEG due to many of the uncertainties that still exist regarding implementation; however, considering the significant investments we have made over the past several years to lower the SO2 and NOx emissions of our fossil plants in the states affected by CSAPR (New Jersey, New York and Pennsylvania), we do not foresee the need to make any significant capital expenditures to our generation fleet to comply with the regulation. As such, we believe this rule will not have a material impact to the financial condition or operations of Power and PSEG.

Hazardous Air Pollutants Regulation

December 31, 2010 Form 10-K page 32 and March 31, 2011 Form 10-Q, page 72. In accordance with a court ruling, the EPA proposed a Maximum Achievable Control Technology (MACT) regulation in March 2011 which is expected to be finalized by November 2011. This regulation includes mercury reduction and other hazardous air pollutants pursuant to the Clean Air Act. In preparation for this action, the EPA solicited extensive stack-testing information from many coal and oil fired electric generating units through a mandatory Information Collection Request (ICR). We 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. Until the final rule is adopted, the impact cannot be determined; however, if the rule is adopted as proposed, we believe the back-end technology environmental controls recently installed at our Hudson and Mercer coal facilities should meet the rule s requirements. At Power s Connecticut facility and some of the other New Jersey facilities, some additional controls could be necessary, pending engineering evaluation. The impact to Power s jointly owned coal fired generating facilities in Pennsylvania is under evaluation.

Water Pollution Control

Permit Renewals

December 31, 2010 Form 10-K page 33 and March 31, 2011 Form 10-Q, page 72. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling through the use of cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant. In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule.

On April 20, 2011, the EPA published the proposed rule with comments currently due on August 18, 2011. The proposed rule would establish a separate marine life entrainment mortality standard as well as new impingement mortality standards for existing cooling water intake structures with a design flow of more than 2 million gallons per day. The proposed impingement standard requires that such facilities must meet specific numeric criteria to comply, while the proposed entrainment standard provides for a site specific, case-by-case

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BTA assessment for mortality reduction. We are in the process of reviewing the proposed rule and assessing its potential impact on our generating facilities. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations. If the rule were to be adopted as proposed, the impact would be material since the majority of our electric generating stations would be affected as they employ once-through cooling utilizing tidal river and tidal waters. We expect to file comments on the proposed rulemaking with the EPA within the prescribed time. See Note 8. Commitments and Contingent Liabilities for additional information.

Conemaugh NPDES permit

March 31, 2011 Form 10-Q, page 72. In April 2007, a Clean Water Act citizen suit was brought against GenOn Northeast Management Company (then known as Reliant Energy Northeast Management Company) (GenOn), as operator of the 1,711 MW Conemaugh Generating Station (Conemaugh), seeking civil penalties and injunctive relief for alleged violations of Conemaugh s National Pollutant Discharge Elimination System (NPDES) permit. We have a 22.5% percent ownership interest in Conemaugh. Pursuant to a Consent Order and Agreement between Pennsylvania Department of Environmental Protection (PADEP) and GenOn, a variety of studies have been conducted, a water treatment facility for cooling tower blowdown has been designed and built, and a second treatment facility for flue gas desulfurization effluent has been designed (awaiting final PADEP approval for construction), in order to comply with the limits set in Conemaugh s NPDES permit. On March 21, 2011, the court entered a partial summary judgment in the plaintiffs favor, declaring as a matter of law that discharges from Conemaugh had violated the NPDES permit.

In May 2011 this matter was settled resulting in the execution of a Consent Decree which was filed with the court. The CWA requires a 45-day comment period after which, barring any opposition, the court will enter the Consent Decree as a final order. It is expected the Consent Decree will be entered on or shortly after August 2, 2011. In addition to specific operating requirements that the Conemaugh Station must implement pursuant to the Consent Decree the parties agreed to a $5 million settlement payment. Our share of the aggregate in costs is approximately $1 million.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10.1:	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011
Exhibit 10.2:	Amendment to Employment Agreement with Randall Mehrberg, dated June 8, 2011
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 101.INS:	XBRL Instance Document*
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema*
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase*
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase*
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase*
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document*

b. Power:

Exhibit 10.1:	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 101.INS:	XBRL Instance Document*
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema*
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase*
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase*
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase*
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document*

c. PSE&G:

Exhibit 10.1:	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

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* XBRL information is furnished, not filed.

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ DEREK M. DIRISIO
Derek M. DiRisio

Vice President and Controller

(Principal Accounting Officer)

Date: August 3, 2011

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG Power LLC
(Registrant)

By: /s/ Derek M. DiRisio
Derek M. DiRisio

Vice President and Controller

(Principal Accounting Officer)

Date: August 3, 2011

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio

Vice President and Controller

(Principal Accounting Officer)

Date: August 3, 2011

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