GenOn Energy, Inc.
Form 10-K
February 29, 2012

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

FORM 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission File Number: 1-16455

GenOn Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0655566** (I.R.S. Employer Identification No.)
1000 Main Street, Houston, Texas (Address of Principal Executive Offices)	**77002** (Zip Code)

(832) 357-3000
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. ý Yes o No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes ý No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes ý No

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $2,965,277,584 on June 30, 2011 (based on $3.86 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day).

As of February 17, 2012, there were 771,692,989 shares of the registrant's Common Stock, $0.001 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's proxy statement for the 2012 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K to the extent described herein.

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Glossary of Certain Defined Terms

AB 32	California's Global Warming Solutions Act.
ancillary services	services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation service, reserves and voltage support.
Bankruptcy Court	United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.
baseload generating units	units designed to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously.
CAIR	Clean Air Interstate Rule.
CAISO	California Independent System Operator.
capacity	amount of energy that could have been generated at continuous full-power operation during the period.
CARB	California Air Resources Board.
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002.
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC	Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act.
Climate Protection Act	Massachusetts' Global Warming Solutions Act.
CO_2	carbon dioxide.
Company	GenOn Energy, Inc. (formerly known as RRI Energy, Inc.) and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.
CPUC	California Public Utility Commission.
CSAPR	Cross-State Air Pollution Rule.
dark spread	the difference between power prices and coal fuel costs.
D.C. Circuit	the United States Court of Appeals for the District of Columbia Circuit.
deactivation	includes retirement, mothball and long-term protective layup. In each instance, the deactivated unit cannot be currently called upon to generate electricity.
Delta Noticing Parties	the Coalition for a Sustainable Delta, four water districts, and an individual.
Dodd-Frank Act	the Dodd-Frank Wall Street Reform and Consumer Protection Act.

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EBITDA	earnings before interest, taxes, depreciation and amortization.
EPA	United States Environmental Protection Agency.
EPC	engineering, procurement and construction.
EPS	earnings per share.
Exchange Act	Securities Exchange Act of 1934, as amended.
Exchange Ratio	right of Mirant Corporation stockholders to receive 2.835 shares of common stock of RRI Energy, Inc. in the Merger.
FASB	Financial Accounting Standards Board.
FCM	forward capacity market administered by ISO-NE to procure capacity resources to meet forecasted demand and reserve requirements.
FERC	Federal Energy Regulatory Commission.
FGD	flue gas desulfurization emissions controls.
FRCC	Florida Reliability Coordinating Council.
GAAP	United States generally accepted accounting principles.
GenOn	GenOn Energy, Inc. (formerly known as RRI Energy, Inc.) and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.
GenOn Americas	GenOn Americas, Inc.
GenOn Americas Generation	GenOn Americas Generation, LLC.
GenOn Energy Holdings	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
GenOn Energy Management	GenOn Energy Management, LLC.
GenOn Escrow	GenOn Escrow Corp.
GenOn Marsh Landing	GenOn Marsh Landing, LLC.
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC and its subsidiaries, which include the baseload units at two generating facilities under operating leases.
GenOn North America	GenOn North America, LLC.
GenOn Potrero	GenOn Potrero, LLC.
HAPs	hazardous air pollutants.
IBEW	International Brotherhood of Electrical Workers.
intermediate generating units	units designed to satisfy system requirements that are greater than baseload and less than peaking.
IRC	Internal Revenue Code of 1986, as amended.
IRC §	IRC section.
ISO	independent system operator.

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ISO-NE	Independent System Operator-New England.
Kiewit	Kiewit Power Constructors Co.
LIBOR	London InterBank Offered Rate.
long-term protective layup	a descriptive term for our plans with respect to the Shawville coal-fired units, including retiring the units from service in accordance with the PJM tariff, maintenance of the units in accordance with the lease requirements and continued payment of the lease rent. While the units are not decommissioned and reactivation remains a technical possibility, we do not expect to make any further investment in environmental controls to the units. Further, reactivation after the long-term protective layup would likely involve numerous new permits and substantial additional investment.
LTPP	Long Term Procurement Planning process by the CPUC.
LTSA	long-term service agreement.
MACT	maximum achievable control technology.
MADEP	Massachusetts' Department of Environmental Protection.
MAEEA	Massachusetts' Executive Office of Energy and Environmental Affairs.
Maryland Greenhouse Gas Act	Greenhouse Gas Reduction Act of 2009.
MATS	Mercury and Air Toxics Standards.
MC Asset Recovery	MC Asset Recovery, LLC.
MDE	Maryland Department of the Environment.
Merger	the merger completed on December 3, 2010 pursuant to the Merger Agreement.
Merger Agreement	the agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
MISO	Midwest Independent Transmission System Operator.
mothball	the unit has been removed from service and is unavailable for service, but has been laid up in a manner such that it can be brought back into service with an appropriate amount of notification, typically weeks or months.
MW	megawatt.
MWh	megawatt hour.
NAAQS	National Ambient Air Quality Standards.
NERC	North American Electric Reliability Council.

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net generating capacity	net summer capacity.
NJDEP	New Jersey Department of Environmental Protection.
NOL	net operating loss.
NOV	notice of violation.
NO_x	nitrogen oxides.
NPCC	Northeast Power Coordinating Council.
NPDES	national pollutant discharge elimination system.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
NYSE	New York Stock Exchange.
OCI	other comprehensive income.
OTC	over-the-counter.
Ozone Season	the period between May 1 and September 30 of each year.
PADEP	Pennsylvania Department of Environmental Protection.
peaking generating units	units designed to satisfy demand requirements during the periods of greatest or peak load on the system.
PEDFA	Pennsylvania Economic Development Financing Authority.
PEPCO	Potomac Electric Power Company.
PG&E	Pacific Gas & Electric Company.
PJM	PJM Interconnection, LLC.
Plan	the plan of reorganization that was approved in conjunction with Mirant Corporation's emergence from bankruptcy protection on January 3, 2006.
$PM_{2.5}$	fine particulate matter.
PPA	power purchase agreement.
Protective Charter Amendment	the Certificate of Amendment to our Third Restated Certificate of Incorporation dated May 4, 2011.
Registration Rights Agreement	the agreement by and among GenOn Energy, Inc. and the initial purchasers of the notes dated as of October 4, 2010.
REMA	GenOn REMA, LLC and its subsidiaries, which include three generating facilities under operating leases.
reserve margin	excess capacity over peak demand.
retire	the unit has been removed from service and is unavailable for service and not expected to return to service in the future.
RFC	Reliability First Corporation.
RFP	request for proposal.

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RGGI	Regional Greenhouse Gas Initiative.
Rights Agreement	the agreement by and among GenOn Energy, Inc. and Computershare Trust Company, NA as rights agent, as subsequently amended.
RMR	reliability-must-run.
RPM	model utilized by PJM to meet load serving entities' forecasted capacity obligations through a forward-looking commitment of capacity resources.
RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Merger.
RTO	Regional Transmission Organization.
SCR	selective catalytic reduction emissions controls.
scrubbers	flue gas desulfurization emissions controls.
SEC	United States Securities and Exchange Commission.
Securities Act	Securities Act of 1933, as amended.
SERC	SERC Reliability Corporation.
Series A Warrants	warrants issued by Mirant on January 3, 2006, with an exercise price of $21.87 and expiration date of January 3, 2011.
Series B Warrants	warrants issued by Mirant on January 3, 2006, with an exercise price of $20.54 and expiration date of January 3, 2011.
SNCR	selective non-catalytic reduction emissions controls.
SO_2	sulfur dioxide.
Southern Company	The Southern Company.
spark spread	the difference between power prices and natural gas fuel costs.
Stone & Webster	Stone & Webster, Inc.
SWD	surface water discharge.
total margin capture factor	the actual gross margin for a unit from energy, and contracted and capacity divided by the total gross margin from energy, and contracted and capacity that could have been earned by the unit.
UWUA	Utility Workers Union of America.
VaR	value at risk.
VIE	variable interest entity.
Virginia DEQ	Virginia Department of Environmental Quality.
WECC	Western Electric Coordinating Council.
Wrightsville	Wrightsville, Arkansas power generating facility, which was sold by Mirant in the third quarter of 2005.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These statements involve known and unknown risks and uncertainties and relate to our revenues, income, capital structure and other financial items, future events, our future financial performance or our projected business results and our view of economic and market conditions. In some cases, one can identify forward-looking statements by words such as "may," "will," "should," "could," "objective," "projection," "forecast," "goal," "guidance," "outlook," "expect," "intend," "seek," "plan," "think," "anticipate," "estimate," "predict," "target," "potential" or "continue" or the negative of these terms or comparable words.

Forward-looking statements are only predictions. Actual events or results may differ materially from any forward-looking statement as a result of various factors, which include:

- more stringent (or changes in the application of) environmental laws and regulations (including the cumulative effect of many such regulations) that restrict our ability or render it uneconomic to operate our assets, including regulations related to air emissions, disposal of ash and other byproducts, wastewater discharge and cooling water systems;

- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities such as coal and natural gas in the energy markets, including efforts to reduce demand for electricity and to encourage the development of renewable sources of electricity, and the extent and timing of the entry of additional competition in our markets;

- legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the industry of generating, transmitting and distributing electricity (the electricity industry); changes in state, federal and other regulations affecting the electricity industry (including rate and other regulations); changes in tax laws and regulations to which we and our subsidiaries are subject; and changes in, or changes in the application of, other laws and regulations to which we and our subsidiaries and affiliates are or could become subject;

- conflicts between reliability needs and environmental rules, particularly with increasingly stringent environmental restrictions;

- price mitigation strategies employed by ISOs or RTOs that reduce our revenue and may result in a failure to compensate our generating units adequately for all of their costs;

- legal and political challenges to or changes in the rules used to calculate payments for capacity, energy and ancillary services or the establishment of bifurcated markets, incentives or other market design changes that give preferential treatment to new generating facilities over existing generating facilities;

- the failure of our generating facilities to perform as expected, including outages for unscheduled maintenance or repair;

- our failure to use new or advanced power generation technologies;

- strikes, union activity or labor unrest;

- our ability to develop or recruit capable leaders and our ability to retain or replace the services of key employees;

weather and other natural phenomena, including hurricanes and earthquakes;

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our failure to provide a safe working environment for our employees and visitors thereby increasing our exposure to additional liability, loss of productive time, other costs and a damaged reputation;

hazards customary to the power generation industry, including those listed in this cautionary statement and elsewhere in this Form 10-K, and the possibility that we may not have adequate insurance to cover losses resulting from such hazards or the inability of our insurers to provide agreed upon coverage;

our ability to execute our plan in respect of our Marsh Landing generating facility, including obtaining and maintaining the governmental authorizations necessary for construction and operation of the generating facility and completing the construction of the generating facility by mid-2013;

our relative lack of geographic diversification of revenue sources resulting in concentrated exposure to the PJM market;

our ability to enter into intermediate and long-term contracts to sell power or to hedge economically our expected future generation of power, and to obtain adequate supplies and deliveries of fuel for our generating facilities, at our required specifications and on terms and prices acceptable to us;

failure to obtain adequate supplies of fuels, including from curtailments of the transportation of fuels;

the cost and availability of emissions allowances;

the curtailment of operations and reduced prices for electricity resulting from transmission constraints;

the potential of additional limitation or loss of our income tax NOLs as a result of an ownership change as defined in IRC § 382;

terrorist activities, cyberterrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss and the possibility that we may not have adequate insurance to cover losses resulting from such hazards or the inability of our insurers to provide agreed upon coverage;

deterioration in the financial condition of our counterparties, including financial counterparties, and the failure of such parties to pay amounts owed to us beyond collateral posted or to perform obligations or services due to us;

poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties, and negative impacts on liquidity in the power and fuel markets in which we hedge economically and transact;

increased credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related pending rulemaking proceedings);

our inability to access effectively the OTC and exchange-based commodity markets or changes in commodity market conditions and liquidity, including as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related pending rulemaking proceedings), which may affect our ability to engage in hedging and proprietary trading activities as expected, or may result in material losses from open positions;

- volatility in our gross margin as a result of changes in the fair value of our derivative financial instruments used in our hedging and proprietary trading activities and volatility in our cash flow from operations resulting from working capital requirements, including collateral, to support our hedging and proprietary trading activities;
- the disposition of pending or threatened litigation, including environmental litigation;
- our ability to access contractors and equipment necessary to operate and maintain our generating facilities and to design, engineer, procure and construct capital improvements required or deemed advisable;
- the inability of our operating subsidiaries to generate sufficient cash to support our operations;
- the ability of lenders under our revolving credit facility and the Marsh Landing credit facility to perform their obligations;
- our consolidated indebtedness and the possibility that we or our subsidiaries may incur additional indebtedness in the future;
- restrictions on the ability of our subsidiaries to pay dividends, make distributions or otherwise transfer funds to us, including restrictions on GenOn Mid-Atlantic and REMA contained in their respective operating lease documents, which may affect our ability to access the cash flows of those subsidiaries to make debt service and other payments;
- our failure or inability to comply with provisions of our leases, loan agreements and debt, which may lead to a breach and, if not remedied, result in an event of default thereunder, which could result in such lessors, lenders and debt holders exercising remedies, limit access to needed liquidity and damage our reputation and relationships with financial institutions;
- covenants contained in our credit facilities, debt and leases that restrict our current and future operations, particularly our ability to respond to changes or take certain actions that may be in our long-term best interests; and
- our ability to borrow additional funds and access capital markets.

Many of these risks, uncertainties and assumptions are beyond our ability to control or predict. All forward-looking statements contained herein are expressly qualified in their entirety by cautionary statements contained throughout this report. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Furthermore, forward-looking statements speak only as of the date they are made. We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report.

In addition to the discussion of certain risks in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the accompanying notes to GenOn's consolidated financial statements, other factors that could affect our future performance are set forth in Item 1A, "Risk Factors." Our filings and other important information are also available on our investor relations page at www.genon.com/investors.aspx.

Certain Terms

As used in this report, unless the context requires otherwise, "we," "us," "our" and "GenOn" refer to GenOn Energy, Inc. and its consolidated subsidiaries, after giving effect to the Merger.

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PART I

Item 1. *Business.*

Overview

We are a wholesale generator with approximately 23,700 MW of net electric generating capacity located, in many cases, near major metropolitan load centers in the PJM, MISO, Northeast and Southeast regions, and California. We also operate integrated asset management and proprietary trading operations. Our customers are principally ISOs, RTOs and investor-owned utilities. Although our generating portfolio is diversified across fossil fuel and technology types, operating characteristics and several regional power markets, approximately 42% and 37% of our realized gross margin during 2011 was attributable to our Eastern PJM and Western PJM/MISO operating segments, respectively. In addition, during 2011, approximately 51% of our realized gross margin was attributable to contracted and capacity energy services.

Our generating capacity is 57% in PJM, 23% in CAISO, 11% in NYISO and ISO-NE, 8% in the Southeast and 1% in MISO. The net generating capacity of these facilities consists of approximately 39% baseload, 40% intermediate and 21% peaking capacity. Our coal facilities generally dispatch as baseload capacity, although some dispatch as intermediate capacity, and our gas, oil and dual fuel plants primarily dispatch as intermediate and/or peaking capacity.

We are subject to extensive environmental regulation by federal, state and local authorities under a variety of statutes, regulations and permits that address discharges into the air, water and soil; and the proper handling of solid, hazardous and toxic materials and waste. Complying with increasingly stringent environmental requirements involves significant capital and operating expenses. To the extent forecasted returns on investments necessary to comply with environmental regulations are insufficient for a particular facility, we plan to deactivate that facility. In determining the forecasted returns on investments, we factor in forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors. We currently expect to deactivate the following generating capacity, primarily coal-fired units, in the referenced years: Niles (217 MW) 2012, Elrama (460 MW) mothball 2012 and retire in 2014, New Castle (330 MW) 2015, Titus (243 MW) 2015, Portland (401 MW) 2015, Shawville (597 MW) place in long-term protective layup in 2015 and Glen Gardner (160 MW) 2015. Further, although our evaluation of the viability of environmental controls for our Avon Lake facility (732 MW) is continuing, our initial analysis indicates that forecasted returns on such investments are insufficient. If such analysis is confirmed, we anticipate retiring the coal-fired units at the Avon Lake facility in 2015. The decision with respect to Avon Lake is influenced in part by retirement decisions announced by other companies that we are continuing to evaluate. In light of the expected retirement or long-term protective layup of the referenced facilities, we do not expect such facilities to participate in PJM's upcoming base residual auction for 2015/2016 in May 2012. We expect industry retirements of coal-fired generating facilities to contribute to a tightening of supply and demand fundamentals and higher prices for the remaining generating facilities. Consequently, we expect the resulting higher market prices to provide adequate returns on investment in environmental controls necessary to meet promulgated and anticipated requirements. Accordingly, we expect to invest approximately $586 million to $726 million over the next ten years for SCRs and other major environmental controls. For further discussion see "Regulatory Environment Environmental Regulation" below and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Environmental Matters."

Merger

On December 3, 2010, Mirant and RRI Energy completed their Merger. Mirant merged with a wholly-owned subsidiary of RRI Energy, with Mirant surviving the Merger as a wholly-owned subsidiary of RRI Energy. In connection with the all-stock, tax-free Merger, RRI Energy changed its name to

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GenOn Energy, Inc., Mirant stockholders received a fixed ratio of 2.835 shares of GenOn common stock for each share of Mirant common stock, and Mirant changed its name to GenOn Energy Holdings.

Although RRI Energy was the legal acquirer, the Merger was accounted for as a reverse acquisition, and Mirant was deemed to have acquired RRI Energy for accounting purposes. As a consequence of the reverse acquisition accounting treatment, the historical financial statements presented for periods prior to the Merger date (and any other financial or operational information presented herein with respect to pre-merger dates, unless otherwise specified) are the historical statements and information of Mirant, except for stockholders' equity, which has been retroactively adjusted for the equivalent number of shares of the legal acquirer. The operations of the former RRI Energy businesses have been included in the financial statements from the date of the Merger. Thus, the consolidated financial statements and financial and operational results of GenOn include the results of Mirant through December 2, 2010 and include the results of the combined entities from December 3, 2010, unless indicated otherwise.

Strategy

Our goal is to create long-term stockholder value across a broad range of commodity price environments. We intend to achieve this goal by:

Successfully integrating the companies and achieving annual cost savings targets. In connection with the Merger, we announced an initial annual cost savings target of $150 million through reductions in corporate overhead and support costs. We have achieved $160 million in such annual cost savings. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 for further information on our cost savings and Merger-related costs.

Leveraging operating and commercial expertise. We have substantial experience in the management, operation and optimization of a portfolio of diverse generating facilities. We operate our generating facilities safely, efficiently, and in an environmentally responsible manner to achieve optimal availability and performance to maximize cash flow.

Transacting to reduce variability in realized gross margin. We develop and execute appropriate hedging strategies to manage risks associated with the volatility in the price at which we sell power and in the prices of fuel, emissions allowances and other inputs required to produce such power. This includes hedging over multiple years to reduce the variability in realized gross margin from our expected generation. In addition, we will continue to sell capacity either bilaterally or through periodic auction processes, which provides a predictable and relatively stable stream of realized gross margin and cash flow.

Maintaining appropriate liquidity and capital structure. Through disciplined balance sheet management and maintaining adequate liquidity, we expect to be able to operate across a broad range of commodity price environments. At December 31, 2011, we had approximately $2.2 billion in total available cash, cash equivalents and availability under our credit facilities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" in Item 7 for information on our liquidity.

Investing capital prudently. Our capital investment decisions are focused on achieving an appropriate return for our stockholders. Capital investments are evaluated independently and include:

- Participating in the development or acquisition of new facilities, such as our investment in the Marsh Landing generating facility;

- Maintaining our existing generating facilities for near and long-term availability; and

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Investing in our existing facilities to improve their competitive position, including capital investments for environmental controls.

Business Segments

We have five operating segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. The table below summarizes selected financial information for our operations by business segment for 2011:

Business Segments	Revenues		Gross Margin[1]		Operating Income (Loss)	
			(dollars in millions)			
Eastern PJM	$ 1,414(2)	39%	$ 859	43%	$ 136	65%
Western PJM/MISO	1,389(2)	38%	735	37%	118	56%
California	238	7%	222	11%	22	11%
Energy Marketing	341(2)	10%	86	4%	80	38%
Other Operations	232	6%	102	5%	(147)	(70)%
Total	$ 3,614	100%	$ 2,004	100%	$ 209	100%

(1) Gross margin excludes depreciation and amortization.

(2) For 2011, we recorded $2.3 billion in revenues from a single counterparty (PJM) which represented 62% of our consolidated revenues. The revenues generated from this counterparty are included in our Eastern PJM, Western PJM/MISO and Energy Marketing segments.

For selected financial information about our business segments, see note 14 to our consolidated financial statements.

Eastern PJM Segment

We own or lease eight generating facilities in the Eastern PJM segment with total net generating capacity of 6,341 MW. The following table presents the details of our Eastern PJM generating facilities:

Facility	Net Generating Capacity (MW)[1]	Holding	In Service Date[2]	Primary Fuel Type[3]	SO_2 and/or NO_x Control Technology[4]	Dispatch Type[5]	Location	NERC Region
Chalk Point	2,401	Own	1964 - 1991	Coal/Dual/Oil	FGD;SCR[6];SACR[7]	B/I/P	Maryland[8]	RFC
Dickerson	849	Own/Lease[9]	1959 - 1993	Coal/Dual/Oil	FGD;SNCR	B/P	Maryland[8]	RFC
Gilbert	536	Own	1970 - 1996	Dual	N/A	I/P	New Jersey	RFC
Glen Gardner[10]	160	Own	1971	Dual	N/A	P	New Jersey	RFC
Morgantown	1,477	Own/Lease[9]	1970 - 1973	Coal/Oil	FGD;SCR	B/P	Maryland[8]	RFC
Potomac River[11]	482	Own	1949 - 1957	Coal	DSI	B/I	Virginia[8]	RFC
Sayreville	224	Own	1972	Dual	N/A	P	New Jersey	RFC
Werner	212	Own	1972	Oil	N/A	P	New Jersey	RFC
Total Eastern PJM	6,341							

(1) Total MW amounts reflect net summer capacity.

(2) Represents the year of commercial operation or range of years if units became operational in different years.

(3) Dual means natural gas and oil.

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(4)
SO_2 controls include FGD and DSI (dry sorbent injection). NO_x controls include SCR, SACR (selective auto-catalytic reduction) and SNCR. In addition, substantially all of our coal units and many of our other units are equipped with combustion controls to reduce NO_x (i.e., low NO_x burners, overfire air systems and/or water injection).

(5)
B is baseload. I is intermediate. P is peaking.

(6)
For Chalk Point unit 1.

(7)
For Chalk Point unit 2.

(8)
These generating facilities are located near Washington, D.C.

(9)
We lease 100% interests in the Dickerson and Morgantown baseload units through facility lease agreements expiring in 2029 and 2034, respectively. We own 307 MW and 248 MW of peaking capacity at the Dickerson and Morgantown generating facilities, respectively. We operate the Dickerson and Morgantown facilities.

(10)
We expect to retire the Glen Gardner generating facility (160 MW) in May 2015.

(11)
We expect to retire the Potomac River generating facility (482 MW) in October 2012.

In January 2011, Stone & Webster, the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown generating facilities, filed three suits against us in the United States District Court for the District of Maryland. The Maryland cases have been stayed pending resolution of a related action we filed against Stone & Webster in New York. See note 16 to our consolidated financial statements.

In August 2011, we entered into an agreement with the City of Alexandria, Virginia to remove permanently from service our Potomac River generating facility on October 1, 2012, subject to the receipt of all necessary consents and approvals. We do not expect the closing of the Potomac River generating facility to have a material effect on our business, results of operations, financial position or cash flows. See note 5 to our consolidated financial statements.

We recently completed an analysis of the cost of environmental controls required for the Glen Gardner facility to comply with the New Jersey High Electric Demand Day regulations. After evaluation of forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors, we concluded that the forecasted returns on investment necessary to comply with these regulations are insufficient. We anticipate that we will retire the Glen Gardner facility in May 2015.

We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. The MDE has sued us regarding Faulkner and Brandywine and threatened to sue regarding Westland. See note 16 to our consolidated financial statements.

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Western PJM/MISO Segment

We own or lease 23 generating facilities in the Western PJM/MISO segment with total net generating capacity of 7,483 MW. The following table presents the details of our Western PJM/MISO generating facilities:

Facility	Net Generating Capacity (MW)[1]	Holding	In Service Date[2]	Primary Fuel Type[3]	SO_2 and/or NO_x Control Technology[4]	Dispatch Type[5]	Location	NERC Region
Aurora	878	Own	2001 - 2002	Natural gas	N/A	P	Illinois	RFC
Avon Lake[6]	753	Own	1949 - 1971	Coal/Oil	SNCR[7]	B/P	Ohio	RFC
Blossburg	19	Own	1971	Natural gas	N/A	P	Pennsylvania	RFC
Brunot Island	289	Own	1972 - 2002	Natural gas/Oil	N/A	I/P	Pennsylvania	RFC
Cheswick	565	Own	1970	Coal	FGD;SCR	B	Pennsylvania	RFC
Conemaugh	281	Lease[8]	1970 - 1971	Coal/Oil	FGD	B/P	Pennsylvania	RFC
Elrama[9]	460	Own	1952 - 1960	Coal	FGD;SNCR	B	Pennsylvania	RFC
Hamilton	20	Own	1971	Oil	N/A	P	Pennsylvania	RFC
Hunterstown	60	Own	1971	Dual	N/A	P	Pennsylvania	RFC
Hunterstown CCGT[10]	810	Own	2003	Natural gas	SCR	B	Pennsylvania	RFC
Keystone	284	Lease[8]	1967 - 1968	Coal/Oil	FGD;SCR	B/P	Pennsylvania	RFC
Mountain	40	Own	1972	Dual	N/A	P	Pennsylvania	RFC
New Castle[11]	330	Own	1952 - 1972	Coal/Oil	SNCR	B/P	Pennsylvania	RFC
Niles[12]	242	Own	1954 - 1972	Coal/Oil	FGD[13];SNCR	B/P	Ohio	RFC
Orrtanna	20	Own	1971	Oil	N/A	P	Pennsylvania	RFC
Portland[14]	570	Own	1958 - 1998	Coal/Dual	N/A	B/P	Pennsylvania	RFC
Seward	525	Own	2004	Coal	CFB/FDA;SNCR	B	Pennsylvania	RFC
Shawnee	20	Own	1972	Oil	N/A	P	Pennsylvania	RFC
Shawville[15]	603	Lease[8]	1954 - 1966	Coal/Oil	SNCR	B/P	Pennsylvania	RFC
Shelby	344	Own	2000	Natural gas	N/A	P	Illinois	SERC
Titus[16]	274	Own	1951 - 1970	Coal/Dual	N/A	B/P	Pennsylvania	RFC
Tolna	39	Own	1972	Oil	N/A	P	Pennsylvania	RFC
Warren	57	Own	1972	Dual	N/A	P	Pennsylvania	RFC
Total Western PJM/MISO	7,483							

(1) Total MW amounts reflect net summer capacity.

(2) Represents the year of commercial operation or range of years if units became operational in different years.

(3) Dual means natural gas and oil.

(4) SO_2 controls include FGD and CFB/FDA (circulating fluidized bed boiler with flash dry absorber). NO_x controls include SCR and SNCR. In addition, substantially all of our coal units and many of our other units are equipped with combustion controls to reduce NO_x (i.e., low NO_x burners, overfire air systems and/or water injection).

(5) B is baseload. I is intermediate. P is peaking.

(6) If our initial analysis is confirmed, we anticipate retiring the coal-fired units at the Avon Lake generating facility in April 2015.

(7) For Avon Lake unit 9.

(8) We lease 100%, 16.67% and 16.45% interests in three Pennsylvania facilities (Shawville, Keystone and Conemaugh, respectively) through facility lease agreements expiring in 2026, 2034 and 2034, respectively. We operate the Shawville, Keystone and Conemaugh facilities. The table includes our net share of the capacity of these facilities.

(9) We expect to mothball the Elrama generating facility (460 MW) in June 2012 and retire it in March 2014.

(10) CCGT means combined cycle gas turbine.

(11) We expect to retire the New Castle generating facility (330 MW) in April 2015.

(12) We expect to retire the coal-fired units at the Niles generating facility (217 MW of the 242 MW) in June 2012.

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(13) For Niles unit 1.

(14) We expect to retire the coal-fired units at the Portland generating facility (401 MW of the 570 MW) in January 2015.

(15) We expect to place the coal-fired units at the Shawville generating facility (597 MW of the 603 MW) in long-term protective layup in April 2015.

(16) We expect to retire the coal-fired units at the Titus generating facility (243 MW of the 274 MW) in April 2015.

The Avon Lake, New Castle and Niles generating facilities moved from the MISO region to the PJM region in June 2011 as a result of the FERC's approval of the transmission owner's request to transfer the operation of its assets from MISO into PJM.

In November 2011, the EPA published a final rule that will require us to reduce our maximum allowable SO_2 emissions from two coal units at our Portland generating facility beginning in January 2013 with even greater reductions in January 2015. We have challenged this rule in federal court. See "Environmental Regulation" and note 16 to our consolidated financial statements.

We recently completed an analysis of the sufficiency of returns on investing in environmental controls required for the units at the Niles, Elrama, New Castle, Titus, Portland and Shawville facilities. These controls will be required primarily as a result of MATS. After evaluation of forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes and other factors, we concluded that the forecasted returns on investments necessary to comply with environmental regulations are insufficient. We currently expect to retire the units at the referenced facilities as set forth below:

- Niles, in June 2012;
- Elrama, in March 2014;
- New Castle, in April 2015;
- Titus, in April 2015; and
- Portland, in January 2015.

In addition, we plan to mothball the Elrama facility in June 2012 and place the coal-fired units at the Shawville facility, which is leased, in a long-term protective layup in April 2015. See "Management's Discussion and Analysis Liquidity and Capital Resources" for a discussion of our obligations under the lease for the Shawville generating facility.

Further, although our evaluation of environmental controls for the Avon Lake facility is continuing, our initial analysis indicates that such investments are not justified and, if such analysis is confirmed, we anticipate retiring the Avon Lake facility in April 2015. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Environmental Matters" for a discussion of expected investments in major environmental controls and the increase in such costs in the event that we conclude that the investment for environmental controls for the Avon Lake facility is justified.

In light of the expected retirement or long-term protective layup of the referenced facilities, we do not expect such facilities to participate in PJM's upcoming base residual auction for 2015/2016 in May 2012.

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California Segment

We own seven generating facilities in California with total net generating capacity of 5,391 MW. In addition, our Marsh Landing project is included in the California segment. The following table presents the details of our current California generating facilities:

Facility	Net Generating Capacity (MW)[1]	Holding	In Service Date[2]	Primary Fuel Type	Dispatch Type[3]	Location	NERC Region
Contra Costa[4]	674	Own	1964	Natural gas	I	California	WECC
Coolwater	636	Own	1961 - 1978	Natural gas	I	California	WECC
Ellwood	54	Own	1974	Natural gas	P	California	WECC
Etiwanda	640	Own	1963	Natural gas	I	California	WECC
Mandalay	560	Own	1959 - 1970	Natural gas	I/P	California	WECC
Ormond Beach	1,516	Own	1971 - 1973	Natural gas	I	California	WECC
Pittsburg	1,311	Own	1960 - 1972	Natural gas	I	California	WECC
Total California	5,391						

(1) Total MW amounts reflect net summer capacity.

(2) Represents the year of commercial operation or range of years if units became operational in different years.

(3) I is intermediate. P is peaking.

(4) We expect to retire the Contra Costa generating facility in May 2013.

Our existing generating facilities in California depend almost entirely on payments they receive to operate in support of system and local reliability through the sale of resource adequacy capacity to load serving entities. The energy, capacity and ancillary services markets, as currently constituted, will not support the capital expenditures necessary to repower or reconstruct our facilities. In order to justify repowering or reconstructing our facilities, we would need to obtain contracts with creditworthy buyers. Absent that, our existing generating facilities in California will be commercially viable only as long as they have contracts for their capacity. See "Commercial Operations" for further discussion.

We have entered into agreements with PG&E to provide electricity from our natural gas-fired units in service at Contra Costa and Pittsburg. We entered into an agreement with PG&E in September 2009 for 674 MW at Contra Costa for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approvals, we have agreed to retire the Contra Costa facility. In addition, we entered into an agreement with PG&E in October 2010 for 1,159 MW at Pittsburg for three years commencing January 2011, with options for PG&E to extend the agreement for each of 2014 and 2015. Under the respective agreements, we will receive monthly capacity payments with bonuses and/or penalties based on heat rate and availability.

In September 2009, GenOn Marsh Landing entered into a ten-year PPA with PG&E for 760 MW of natural gas-fired peaking generation to be constructed adjacent to our Contra Costa generating facility near Antioch, California. During the ten-year term of the PPA, GenOn Marsh Landing will receive fixed monthly capacity payments and variable operating payments. The contract provides PG&E with the entire output of the generating facility, which is expected to be capable of producing 719 MW during peak summer conditions.

In May 2010, GenOn Marsh Landing entered into an EPC agreement with Kiewit for the construction of the Marsh Landing generating facility. Under the EPC agreement, Kiewit is to design and construct the Marsh Landing generating facility on a turnkey basis, including all engineering, procurement, construction, commissioning, training, start-up and testing. The lump sum cost of the EPC agreement is $505 million (including the $212 million total cost under the Siemens Turbine Generator Supply and Services Agreement which was assigned to Kiewit in connection with the execution of the EPC agreement), plus the reimbursement of California sales and use taxes. See "Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations" in "Liquidity and Capital Resources" and note 10 to our consolidated financial statements.

In October 2010, GenOn Marsh Landing entered into a credit agreement for up to $650 million of commitments to finance the Marsh Landing generating facility. See note 6 to our consolidated financial statements.

GenOn Marsh Landing received all permits necessary to begin construction and, in October 2010, directed Kiewit to commence engineering and procurement for and construction of the Marsh Landing generating facility. Construction of the Marsh Landing generating facility is expected to be completed by mid-2013.

In January 2011, at our request, the FERC approved changes to the RMR agreement for our Potrero facility in San Francisco, California to allow the CAISO to terminate the RMR agreement effective February 2011. In February 2011, the Potrero facility was shut down in compliance with our November 2009 settlement agreement with the City and County of San Francisco.

Energy Marketing Segment

In the markets in which we operate, we support our operations with fuel oil management and natural gas transportation and storage activities, as well as engage in proprietary trading when we identify opportunities. These activities include the purchase and sale of electricity, fuel and emissions allowances, sometimes through financial derivatives.

We engage in fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. We engage in natural gas transportation and storage activities to optimize our physical natural gas and storage positions and manage the physical gas requirements for a portion of our assets.

Proprietary trading, fuel oil management and natural gas transportation and storage activities together typically comprise less than 5% of our realized gross margin. All of these activities are governed by a comprehensive risk management policy, which includes limits on the size of volumetric positions and VaR for our proprietary trading and fuel oil management activities and requires all incremental natural gas transportation and natural gas storage activities to be risk reducing. For 2011, our combined average daily VaR for proprietary trading and fuel oil management activities was $2 million.

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Other Operations Segment

Our Other Operations segment is comprised of our generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas with total net generating capacity of 4,482 MW. The following table presents the details of our Other Operations generating facilities:

Facility	Net Generating Capacity (MW)[1]	Holding	In Service Date[2]	Primary Fuel Type[3]	Dispatch Type[4]	Location	NERC Region
Bowline	1,139	Own	1972 - 1974	Dual	I	New York	NPCC
Canal	1,126	Own	1968 - 1976	Dual/Oil	I	Massachusetts	NPCC
Choctaw	800	Own	2003	Natural gas	B	Mississippi	SERC
Indian River[5]	586	Own	1964	Dual	I	Florida	FRCC
Kendall[6]	256	Own	1949 - 2002	Natural gas/Oil/Dual	B/P	Massachusetts	NPCC
Martha's Vineyard	14	Own	1968 - 1972	Oil	P	Massachusetts	NPCC
Osceola	463	Own	2001 - 2002	Dual	P	Florida	FRCC
Sabine[7]	54	Own	1999	Natural gas	B	Texas	SERC
Vandolah	630	Lease[8]	2002	Dual	P	Florida	FRCC
Total Other Operations	4,482						

(1) Total MW amounts reflect net summer capacity.

(2) Represents the year of commercial operation or range of years if units became operational in different years.

(3) Dual means natural gas and oil.

(4) B is baseload. I is intermediate. P is peaking.

(5) The Indian River generating facility was sold in January 2012; therefore, its megawatts are excluded from total net generating capacity.

(6) The Kendall generating facility, which is a cogeneration facility, has long-term agreements under which it sells steam.

(7) We own a 50% equity interest in the Sabine facility located in east Texas having a net generating capacity of 108 MW. An unaffiliated party owns the other 50% and an affiliated party to the other owner operates the facility. The table includes our net share of the capacity of this facility.

(8) We are party to a tolling agreement that expires in May 2012 and entitles us to purchase and dispatch 100% of this facility's electric generating capacity. The tolling agreement is treated as an operating lease for accounting purposes.

In the fourth quarter of 2010, we identified potential risks associated with some equipment that reduced the available capacity of one of the units at the Bowline generating facility. We are in the process of evaluating long-term solutions for the generating facility, but we expect that the reduction in available capacity will extend through 2014. Unrelated to the reduction in available capacity, we are repairing the facility's transmission and gas supply lines which were damaged by Hurricane Irene in August 2011. Until these repairs are completed, the facility cannot be dispatched. We expect to complete these repairs in May 2012.

Commercial Operations

We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States, including ISOs and RTOs, power aggregators, retail providers, electric-cooperatives, other power generating companies and other load serving entities. Our commercial operations consist primarily of dispatching electricity, hedging the price of electricity we expect to generate, selling capacity, procuring and managing fuel and providing logistical support for the operation of our facilities (for example, by procuring transportation for coal and natural gas), as well as our proprietary trading operations.

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We sell capacity either bilaterally or through periodic auction processes in each ISO and RTO market in which we participate. Our capacity sales primarily occur through the PJM RPM and ISO-NE FCM auctions, but also in CAISO, MISO, NYISO and other markets where we enter into agreements with counterparties. We expect that a substantial portion of our PJM capacity will continue to be sold in PJM up to three years in advance. Revenue from these capacity sales is determined by market rules designed to ensure regional reliability, encourage competition and reduce energy price volatility. These capacity sales provide an important source of predictable revenues for us over the contracted periods. At January 24, 2012, total projected contracted capacity and PPA revenues for which prices have been set for 2012 through 2015 are $3.0 billion. Failure to meet our capacity commitments may result in a reduction to our capacity payments through penalties or charges.

As a part of our strategy, we enter into economic hedges forward sales of electricity and forward purchases of fuel and emissions allowances to manage the risks associated with volatility in prices for electricity, fuel and emissions allowances and to achieve more predictable financial results. In addition, given the high correlation between natural gas prices and electricity prices in many of the markets in which we operate, we enter into forward sales of natural gas to hedge economically our exposure to changes in the price of electricity. We procure our hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options. Our hedges cover various periods, including several years.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this Form 10-K for our aggregate hedge levels based on expected generation for 2012 to 2016. In addition, see Item 1A, "Risk Factors Risks Related to Economic and Financial Market Conditions" for a discussion of the risks associated with implementation of the Dodd-Frank Act on our ability to hedge economically our generation, including potentially reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

Power

We hedge economically a substantial portion of our PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. A significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices.

Although standard industry OTC transactions make up a substantial portion of our economic hedge portfolio, at times we sell non-standard, structured products to customers, primarily financial institutions. These products include fixed load shapes, load following arrangements, heat rate options and financial or physical tolls.

Several of our California, Florida and Mississippi generating facilities typically operate under contracts for their capacity or energy. See "Business Business Segments California Segment" for information regarding California contracts.

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Fuel

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2014 and one that extends to 2020. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K for discussion of our coal agreement risk. For our oil-fired units, we typically purchase fuel from a small number of suppliers either in the spot market or under contracts with terms of varying lengths. For our natural gas-fired facilities, in addition to purchasing natural gas, we arrange for and schedule its transportation through pipelines. To perform a portion of these functions, we lease natural gas transportation and storage capacity. We sell excess fuel supplies to third parties.

We receive coal at our generating facilities primarily by rail and truck. In addition, we can receive coal by barge at our Morgantown, Cheswick and Elrama plants. We use coal blending facilities at our Conemaugh, Morgantown and Titus generating facilities that allow for greater flexibility of coal supply by allowing various coal qualities to be blended while also meeting emissions targets. We monitor coal supply and delivery logistics carefully but there are occasional interruptions of planned deliveries caused by weather, operational or transportation issues. Because of the risk of disruptions in our coal supply, we strive to maintain adequate targeted levels of coal inventories at our coal-fired facilities.

Emissions

Our commercial operations manage the acquisition and use of emissions allowances for our generating facilities. We trade emissions allowances for SO_2, NO_x and CO_2 and manage the risk surrounding emissions exposure in federal, state and regional compliance programs applicable to our generating facilities. Because of our investments in environmental controls made over the past 12 years to our existing generation fleet that we expect to remain after the deactivations, our NO_x emissions have been reduced by approximately 78% and SO_2 emissions have been reduced by approximately 90% from the 1990 levels. See " Regulatory Environment Environmental Regulation" for a discussion of major environmental controls investments we expect to make over the next ten years.

Coal Combustion Byproducts

Existing state and federal rules require the proper management and disposal of wastes and other materials. We produce byproducts from our coal-fired generating units, including ash and gypsum. We actively manage the current and planned disposition of each of these byproducts. All of our ash disposal facilities are dry landfills (although we do use ponds to dewater ash at some facilities). Our disposal plan for ash includes land-filling at our existing ash management facilities, purchasing and permitting additional disposal sites, using third parties to handle and dispose of the ash, and construction of an ash beneficiation facility at our Morgantown site to make the ash more suitable for sale to third parties for the production of concrete as well as other beneficial uses. We have constructed the ash beneficiation facility and expect the facility to begin commercial operations during the first half of 2012. Our disposal plan for gypsum includes selling it to third parties for use in the production of drywall and disposing of it in approved landfills. Currently, we expect to invest approximately $40 million in capital expenditures over the next five years for ash landfill modifications and expansions.

There is increased focus on the regulation of coal combustion products and, if the manner in which they are regulated changes, we may be required to change our management practices for these byproducts and/or incur additional costs. See note 16 to our consolidated financial statements for information regarding litigation and other contingencies with respect to our Maryland fly ash facilities.

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The Dodd-Frank Act

The Dodd-Frank Act, which was enacted in July 2010, increases the regulation of transactions involving OTC derivative financial instruments. The statute provides that standardized swap transactions between dealers and large market participants will have to be cleared and traded on an exchange or electronic platform. Although the provisions and legislative history of the Dodd-Frank Act provide strong evidence that market participants, such as us, which utilize OTC derivative financial instruments to hedge commercial risks are not to be subject to these clearing and exchange-trading requirements, it is uncertain what the final implementing regulations will provide. The effect of the Dodd-Frank Act on our business depends in large measure on pending rulemaking proceedings of the CFTC, the SEC and the federal banking regulators. Under the Dodd-Frank Act, entities defined as "swap dealers" and "major swap participants" (SD/MSPs) will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. The CFTC and SEC issued a proposed rulemaking to set final definitions for the terms "swap dealer" and "major swap participant" among others. Although we do not expect our commercial activity to result in our designation as an SD/MSP, as proposed, the "swap dealer" definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. It is possible that the final rule will not offer much clarity and the designation as an SD/MSP could be decided by facts and circumstance tests. We expect the final rule to be released in the first quarter of 2012.

In addition, the CFTC and federal banking regulators, who will regulate bank SD/MSPs, separately issued proposed rules to establish capital and margin requirements for SD/MSPs and swap counterparties. While end-user counterparties who are using a swap to hedge or mitigate commercial risk would be generally exempt from mandatory margin requirements under the CFTC's proposal applicable to non-bank SD/MSPs, they would have to post cash margin to bank SD/MSPs if they exceed exposure thresholds under the federal banking regulators' proposal. The federal banking regulators' rulemaking states that the credit support limit shall be determined by the bank SD/MSPs in accordance with their normal credit processes to set credit limits and to collect initial and variation margin. As proposed, the federal banking regulators' rulemaking does not specify a procedure for determining such thresholds and a major question remains of the extent to which end-users and bank SD/MSPs will be free under the proposal to set their own thresholds to avoid the collection of margin from end-users. If applied to our hedging activity, such regulations could materially affect our ability to hedge economically our generation by significantly increasing the collateral costs associated with such activities. Furthermore, the CFTC and federal banking regulators' proposed capital requirements for SD/MSPs recommend significant and cash-dependent capital requirements for SD/MSPs. The cost of complying with these requirements may be passed through to and imposed on commercial end users indirectly and increase the cost of our hedging activities.

The CFTC has also issued its proposed definition of "swap." In further defining the term, the CFTC has left some ambiguity as to whether what are commonly understood as commodity options (which can settle physically) are to be generally considered swaps. With regard to electric power ISO/RTO products, including Financial Transmission Rights, the CFTC has said only that it will consider granting exemptions to transactions where an instrument regulated by FERC is involved and such an exclusion would be in the public interest. Several ISO's, including PJM, CAISO, ISO-NE and the NYISO, have recently filed the exemption application with the CFTC. If applied to our hedging activity, such regulations could considerably increase the transaction costs with respect to commodity options and Financial Transmission Rights.

In September 2011, the CFTC proposed swaps compliance and implementation schedules for mandatory clearing and trading, trading documentation and uncleared margin. The CFTC's notice of proposed rulemaking would give the CFTC discretion to phase in implementation of any clearing mandate for 90, 180 or 270 days, depending on the types of entities that are party to the relevant swap. The trigger for the implementation phase-in period would be the issuance of a clearing mandate by the CFTC. The

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CFTC also issued a further notice of proposed rulemaking with respect to margin and documentation requirements that would establish implementation schedules of 90, 180 or 270 days, depending on the types of entities involved. The CFTC has proposed, but not yet adopted, regulations implementing both of these provisions. As the entity and product definitions have not been finalized, we cannot fully assess the impact on us of these proposals.

Lastly, in October 2011, the CFTC adopted final rules on speculative position limits that will apply to 28 futures contracts and any economically equivalent futures, options and swaps. The rules also establish new reporting requirements for persons holding or controlling positions in certain referenced contracts in excess of particular limits and amend the scope of the bona fide hedging exemption. At this time, we do not expect the position limits to have a material effect on our commercial activities.

Competitive Environment

The power generating industry is capital intensive and highly competitive. In addition, the wholesale power generation industry is highly fragmented compared to other commodity industries. There is wide variation in terms of the capabilities, resources, nature and identity of the companies with which we compete. Our competitors include regulated utilities, merchant energy companies, financial institutions and other companies. For a discussion of competitive factors see Item 1A, "Risk Factors." Coal-fired, natural gas-fired, nuclear and hydroelectric generation currently account for approximately 43%, 25%, 19% and 8%, respectively, of the electricity produced in the United States. Other energy sources account for the remaining 5% of electricity produced.

Our large coal generating fleet is exposed to the relationship between the cost of production and the price of the power produced. This relationship, commonly referred to as the dark spread, fluctuates with the cost of coal and the price of power. We hedge economically a substantial portion of our PJM coal-fired baseload generation and certain of our other generation. We seek to hedge economically our output at varying levels several years in advance because the price of electricity is volatile. In addition, we enter into contracts to hedge economically our future needs of coal, which is our primary fuel. The prices for power and natural gas are low compared to several years ago. The energy gross margin from our generating facilities is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally economically neutral to subsequent changes in commodity prices because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue to seek to add economic hedges to maintain projected levels of cash flows from operations for future periods and to help support continued compliance with the covenants in our debt and lease agreements.

Given the substantial time required to permit and construct new power plants, the process to add generating capacity must begin years in advance of anticipated growth in demand. A number of ISOs and RTOs, including those in markets in which we operate, have implemented capacity markets designed to provide forward prices for capacity that ensure that adequate resources are in place to meet the region's demand. Over the last several years, very little new generation has been constructed as a result of the economic downturn and programs to reduce the demand for electricity which have resulted in a decrease in the rate at which the long-term demand for electricity is forecasted to grow. See "Regulatory Environment" later in this section for further discussion.

The costs to construct new generating facilities have been rising, and there is substantial environmental opposition to building either coal-fired or nuclear plants. We have sufficient room and infrastructure at many of our existing sites to increase significantly our generating capacity when market rules, prices and conditions warrant. In addition to reduced costs for developing new generation at existing sites because of our ownership of the land and our ownership of and/or access to infrastructure, regulators frequently prefer that new generation be added at existing sites (brownfield development) rather than at new sites (greenfield development). We continue to consider these and other investment opportunities.

Many of our generating facilities are located in or near metropolitan areas, including Boston, New York City, Pittsburgh, San Francisco, Southern California/Los Angeles and Washington, D.C. The supply-demand balance in some of these markets is forecasted to become constrained and increasingly dependent on power imported from other regions to sustain reliability. However, there are proposed upgrades to the transmission systems in some of the markets in which we operate that could mitigate the need for existing marginal generating capacity and for new generating capacity. Additionally, new facilities have been proposed or developed in some of these markets that will increase or have increased available sources of supply. To the extent that these upgrades are completed and new facilities are built, prices for electricity and capacity could be lower in some of our markets than they might otherwise be. Furthermore, the prices for power and natural gas remain at historically low levels. See "Commercial Operations."

Concern over the environmental impacts of climate change and fossil-fueled generating station air emissions has led to significant legislative and regulatory efforts at the state and federal level. The costs of compliance with such efforts could affect our ability to compete in the markets in which we operate, especially with our coal-fired generating facilities. See "Regulatory Environment" and "Environmental Regulation" for further discussion.

Seasonality

For information on the effect of seasonality on our business, see "Risk Factors" in Item 1A in this Form 10-K and note 15 to our consolidated financial statements.

Regulatory Environment

Federal, State and Local Regulations

FERC. The electricity industry is regulated extensively at the federal, state and local levels. At the federal level, the FERC has exclusive jurisdiction under the Federal Power Act over sales of electricity at wholesale and the transmission of electricity in interstate commerce. Each of our subsidiaries that owns or leases a generating facility selling at wholesale or that markets electricity at wholesale is a "public utility" subject to the FERC's jurisdiction under the Federal Power Act. These subsidiaries must comply with certain FERC reporting requirements and FERC-approved market rules and they are subject to FERC oversight of mergers and acquisitions, the disposition of facilities under the FERC's jurisdiction and the issuance of securities.

The FERC has authorized our subsidiaries that are public utilities under the Federal Power Act to sell wholesale energy, capacity and certain ancillary services at market-based rates. The majority of the output of the generating facilities owned by our subsidiaries is sold pursuant to this market-based rate authorization. The FERC could revoke or limit our market-based rate authority if it were to determine that we possess insufficiently mitigated market power in a regional electricity market. Under the Natural Gas Act, our subsidiaries that sell natural gas for resale are deemed by the FERC to have blanket certificate authority to undertake these sales at market-based rates.

The FERC requires that our public utility subsidiaries with market-based rate authority and our subsidiaries with blanket certificate authority adhere to general rules against market manipulation as well as to certain market behavior rules and codes of conduct. If any of our subsidiaries were found to have engaged in market manipulation, the FERC has the authority to impose a civil penalty of up to $1 million per day per violation. In addition to the civil penalties, if any of our subsidiaries were to engage in market manipulation or violate the market behavior rules or codes of conduct, the FERC could require a disgorgement of profits related to the improper activity or could revoke the subsidiary's market-based rate

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authority or blanket certificate authority. If the FERC were to revoke market-based rate authority, our affected public utility subsidiary would have to file a cost-based rate schedule for all or some of its sales of electricity at wholesale.

Our subsidiaries owning generating facilities have made such filings, and received such orders, as are necessary to obtain exempt wholesale generator status under the Public Utility Holding Company Act of 2005 and the FERC's regulations thereunder. Provided all of our subsidiaries owning or leasing generating facilities continue to be exempt wholesale generators, or are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, we and our intermediate holding companies owning direct or indirect interests in those subsidiaries will remain exempt from the accounting, record retention and reporting requirements that the Public Utility Holding Company Act of 2005 imposes on "holding companies."

NERC. In 2006, the FERC certified NERC as the national energy reliability organization. NERC is responsible for the development and enforcement of mandatory reliability standards, including cyber-security standards, for the electric power system. Each of our subsidiaries selling electricity at wholesale is responsible for complying with the reliability standards in the region in which it operates. Assets that have been determined to be critical physical or cyber-security assets are not accessible via the internet. NERC has the ability to assess financial penalties for non-compliance with the reliability standards, which penalties can, depending on the nature of the non-compliance, be significant. In addition to complying with the NERC standards, each of our entities selling electricity at wholesale must comply with the reliability standards of the regional reliability council for the NERC region in which its sales occur.

State and Local. State and local regulatory authorities historically have overseen the distribution and sale of electricity at retail to the ultimate end user, as well as the siting, permitting and construction of generating and transmission facilities. Our existing generating facilities are subject to a variety of state and local regulations, including regulations regarding the environment, health and safety and maintenance and expansion of the facilities.

In some markets, state regulators have proposed initiatives to provide long-term contracts for new generating capacity in order, among other things, to reduce future capacity prices in PJM. In January 2011, New Jersey enacted legislation which requires the Board of Public Utilities to implement a Long Term Capacity Agreement Pilot Program providing for new generating capacity in the state. The new generating capacity would be required to participate and be accepted as a capacity resource in the PJM capacity market. The New Jersey Board of Public Utilities awarded three contracts for new generating capacity as required by the statute. Because the law could have a negative effect on capacity prices in PJM in future years, a group of companies in February 2011 filed suit in the U.S. District Court for New Jersey asking the court to declare the New Jersey legislation unconstitutional. That proceeding continues.

In September 2011, the Maryland Public Service Commission issued an RFP for up to 1,500 MWs of new natural gas-fired generating capacity to be located in the Southwestern Mid-Atlantic Area Council zone of PJM. The RFP requires any such new generating capacity to bid into the capacity markets in a manner consistent with the PJM tariff. The order provided for project submittals in January 2012 and a Maryland Public Service Commission hearing, later in January 2012, to determine whether new generating capacity is needed to meet the long-term anticipated demand in Maryland. We filed comments with the Maryland Public Service Commission stating there is no need for additional capacity at this time. The Maryland Public Service Commission has not issued a final decision on whether it will require the electric distribution utilities in the state to enter into contracts for new generating capacity. Such contracts could have a negative effect on capacity prices and energy prices in PJM in future years.

In April 2011, the FERC ordered changes in the PJM tariff to prevent interference with the capacity markets by efforts such as the New Jersey legislation and the Maryland RFPs.

Because of the interest of these two states in building new generating capacity within their respective states and the possibility of future RFPs for new generating capacity, we have filed interconnection requests for new generating capacity at our Sayreville generating facility in New Jersey and our Dickerson generating facility in Maryland to begin the process of reviewing the suitability of these sites on the transmission grid. We have not decided to build new generating capacity at either facility.

In California, instead of implementing a centralized capacity market to incent the construction of new, in-state generating capacity, the CPUC addresses the need for new, in-state generating capacity through its LTPP rulemakings. In February 2012, the CPUC issued a proposed decision in the current LTPP rulemaking. That proposed decision, if adopted, would approve a settlement agreement that concludes that there is inadequate evidence in the record to authorize the procurement of new generating capacity in the PG&E and Southern California Edison service areas. We have sites with existing facilities in both service areas. The settlement agreement further provides that additional analysis would be necessary to determine what impacts the integration of new renewable generating resources (both existing and planned) and the future retirement of facilities with once-through cooling will have on the need for new generating capacity. The proposed decision, if adopted, would also place limits on PG&E's and Southern California Edison's authority to contract with units that rely on once-through cooling. See below under " Environmental Regulation Water Regulations." Although the settlement agreement contemplates that the additional analysis regarding the need for new generating capacity will occur during 2012, with a decision by the CPUC by the end of 2012, this timeline is uncertain. If the decision identifies a need for new generating capacity, we will evaluate whether to participate in the resulting processes requesting offers run by PG&E, Southern California Edison or both.

ISOs and RTOs. The vast majority of our facilities operate in markets administered by ISOs and RTOs. In areas where ISOs or RTOs control the regional transmission systems, market participants have access to broader geographic markets than in regions without ISOs and RTOs. ISOs and RTOs operate day-ahead and real-time energy and ancillary services markets, typically governed by FERC-approved tariffs and market rules. Some ISOs and RTOs also operate capacity markets. Changes to the applicable tariffs and market rules may be requested by the ISO or RTO, or by other interested persons, including market participants and state regulatory agencies, and such proposed changes, if approved by the FERC, could have a significant effect on our operations and financial results. Although participation in ISOs and RTOs by public utilities that own transmission has been, and is expected to continue to be, voluntary, the majority of such public utilities in California, Illinois, Maryland, Massachusetts, New Jersey, New York, Ohio, Pennsylvania and Virginia have joined the applicable ISO and RTO.

PJM. Our Eastern and Western PJM generating facilities sell electricity into the markets operated by PJM. We have access to the PJM transmission system pursuant to PJM's Open Access Transmission Tariff. PJM operates the PJM Interchange Energy Market, which is the region's spot market for wholesale electricity, provides ancillary services for its transmission customers, performs transmission planning for the region and economically dispatches generating facilities. PJM administers day-ahead and real-time single clearing price markets and calculates electricity prices based on a locational marginal pricing model. A locational marginal pricing model determines a price for energy at each node in a particular zone taking into account the limitations and losses on transmission of electricity into the zone, resulting in a higher zonal price when less expensive energy cannot be imported from another zone. Generation owners in PJM are subject to mitigation, which limits the prices that they may receive under certain specified conditions.

Load-serving entities within PJM are required to have adequate sources of capacity. Our generating facilities located in the Eastern and Western PJM region that sell electricity into the PJM market participate in the RPM forward capacity market. The PJM RPM capacity auctions are designed to provide forward prices for capacity that ensure that adequate resources are in place in the correct location to meet the region's demand requirements. PJM has conducted numerous capacity auctions

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since RPM's inception in 2007 with the next annual auction scheduled to take place in May 2012 for the provision of capacity from June 2015 to May 2016. PJM continues to revise elements of the RPM provisions of its tariff, both pursuant to those provisions and on its own volition or at the request of its stakeholders. These revisions must be filed with and approved by the FERC, and we, either individually or as part of a group, are actively involved at the FERC to protect our interests. See previous discussion under "FERC" for our involvement at the FERC.

MISO. Our MISO generating facility sells electricity into the markets operated by MISO. MISO manages the transmission system and provides open access to its transmission system and markets to all market participants on an equal basis. MISO operates physical and financial energy markets using a locational marginal pricing model, which calculates a price for every generator and load point within MISO and is similar to the model utilized by PJM. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. MISO does not currently administer a centralized capacity market; instead it uses an enforceable Planning Reserve Margin to ensure resource adequacy. In July 2011, MISO filed with the FERC a proposal for an auction mechanism to meet locational reserve requirements which will be established for each planning year. If accepted by the FERC, the first auction would take place in April 2013 for the June 2013 to May 2014 planning year. MISO also has an ancillary services market. A feature of the ancillary services market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh.

California. Our California generating facilities are located inside the CAISO's control area. The CAISO operates wholesale electricity markets whose key components include locational marginal pricing of energy that is similar to the locational marginal pricing in the RTO/ISO markets in the east, day-ahead and real-time markets and a transmission congestion management system. The CAISO also schedules transmission transactions and arranges for necessary ancillary services. Most sales of electricity in California are made pursuant to bilateral contracts, but a significant percentage of electrical energy is sold in the day-ahead and real-time markets operated by the CAISO.

Although the CAISO does not operate a centralized capacity market, the CPUC has adopted resource adequacy requirements for load-servicing entities that require those load-serving entities to procure capacity on a forward basis in an amount deemed appropriate to ensure reliable operation. This resource adequacy obligation creates an opportunity for our California generating facilities to generate revenue through a capacity service offering.

In the absence of a centralized capacity market, California relies on the CPUC's biannual LTPP process to identify the need for new generating capacity in the service areas of the three major electrical utilities that the CPUC regulates. The contract for the Marsh Landing generating facility was awarded based on procurement authority identified in an LTPP process. We continue to monitor the CPUC's LTPP proceedings to identify potential opportunities for new generating facilities.

Other Operations. Our Bowline generating facility participates in a market administered by the NYISO. The NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, the NYISO calculates energy prices using a locational marginal pricing model. The NYISO also administers a spot market for energy, as well as markets for installed capacity and services that are ancillary to transmission service. The NYISO's locational capacity market utilizes a demand curve mechanism to determine monthly capacity prices to be paid to suppliers for three capacity zones: New York City, Long Island and Rest of State. Our facility is located in the Rest of State capacity zone. In September 2011, the FERC directed the NYISO to submit changes to its market rules to include criteria for the creation of new capacity zones in the NYISO's capacity market. If the FERC accepts the NYISO's November 2011 filing of the criteria for creating new capacity zones, it is possible that a new Lower

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Hudson Valley capacity zone could be created in time for the May 2014 monthly capacity auction. Our facility likely would be located in the new Lower Hudson Valley capacity zone.

Our Canal, Kendall and Martha's Vineyard generating facilities participate in a market administered by ISO-NE. We are a member of the New England Power Pool, which is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and which functions as an advisory organization to ISO-NE. As the RTO for the New England region, ISO-NE is responsible for the operation of transmission systems and for the administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model for electric energy similar to the model used in PJM, MISO and NYISO. Our generating facilities located in ISO-NE also participate in the FCM. The FCM is designed to provide forward prices for capacity that ensure that adequate resources are in place to meet the region's demand. ISO-NE has conducted numerous FCMs and we began receiving payments in June 2010 as a result of the first auction.

Our Choctaw, Sabine and Osceola generating facilities located in the Southeast region do not operate in a market that is operated by an RTO or ISO. Opportunities to negotiate bilateral contracts and long-term transactions with investor owned utilities, municipalities and cooperatives exist within this region. In addition to entering into bilateral transactions, there is a limited opportunity to sell into the short-term market. Access to the transmission system in this region to which the generating facility is interconnected is governed by the FERC approved terms and conditions of the applicable transmission provider's open access transmission tariff.

In the Entergy Corporation sub-region, which the Choctaw facility can access, Southwest Power Pool has been designated as the Independent Coordinator of Transmission. In this capacity, the Independent Coordinator of Transmission provides oversight of the Entergy transmission system. In April 2011, Entergy Corporation announced that it was joining MISO with a targeted integration date of December 2013. If Entergy Corporation successfully joins MISO, our Choctaw facility should be able to participate in MISO's day-ahead and real-time markets. In December 2011, Entergy Corporation announced that it will divest and then merge its transmission assets into ITC Holdings Corp., an independent transmission company, in 2013.

Environmental Regulation

We are subject to extensive environmental regulation by federal, state and local authorities under a variety of statutes, regulations and permits that address the discharge of materials into the air, water and soil; the proper handling of solid, hazardous and toxic materials and waste; and noise, safety and health standards applicable to the workplace. Complying with these environmental requirements involves significant capital and operating expenses. We decide to invest capital for environmental controls based on relatively certain regulations, an evaluation of various options for regulatory compliance, including different technologies and fuel modification, and the expected economic returns on the capital. As previously stated, we expect industry retirements to contribute to a tightening of supply and demand fundamentals and higher prices for the remaining generating facilities. Consequently, we expect the resulting higher market prices to provide adequate returns on investment in environmental controls necessary to meet promulgated and anticipated requirements. Accordingly, we expect to invest approximately $586 million to $726 million over the next ten years for SCRs and other major environmental controls to meet certain NAAQS, New Jersey NO_x, MATS and various water quality requirements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures and Capital Resources" and "Environmental Matters" for additional information. Some of these requirements are under revision and/or in dispute, and some new requirements are pending or under consideration.

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Air Emissions Regulations

The Clean Air Act and the resulting regulations (as well as similar state and local requirements) have been and will continue to be a focal point for us because they mandate a broad range of requirements concerning air quality, air emissions, operating practices and pollution control equipment. Under the Clean Air Act, the EPA sets NAAQS for pollutants thought to be harmful to public health and the environment, including SO_2, ozone, and fine particulate matter ($PM_{2.5}$). Most of our facilities are located in or near areas that are classified by the EPA as not achieving certain NAAQS (non-attainment areas). The relevant NAAQS have become more stringent and we expect that trend to continue. As a result of such classification and the manner in which regulators seek to achieve the NAAQS, our operations generally are subject to more stringent air pollution requirements than those applicable to facilities located elsewhere. The states are generally free to impose requirements that are more stringent than those imposed by the federal government. We expect increased regulation at both the federal and state levels of our air emissions. We maintain a comprehensive compliance strategy to address these continuing and new requirements. Complying with increasingly stringent NAAQS may require us to install and operate additional emissions control equipment at some of our facilities if we decide to continue to operate such facilities. Subject to market prices, and based on anticipated more stringent NAAQS for ozone and $PM_{2.5}$, we expect to invest between $315 million and $418 million in capital expenditures during 2018 to 2021 at our Chalk Point and Dickerson generating facilities. Significant air regulatory programs to which we are subject are described below.

Cross-State Air Pollution Rule. In 2005, the EPA promulgated the CAIR, which established SO_2 and NO_x cap-and-trade programs applicable directly to states and indirectly to generating facilities in the eastern United States. The NO_x cap-and-trade program has two components: an annual program and an ozone-season program. The CAIR SO_2 cap-and-trade program builds off the existing acid rain cap-and-trade program but requires generating facilities to surrender twice as many allowances to cover emissions from 2010 through 2014 and approximately three times as many allowances starting in 2015. Florida, Illinois, Maryland, Mississippi, New Jersey, New York, Ohio, Pennsylvania and Virginia are subject to the CAIR's SO_2 trading program and both its NO_x trading programs. Massachusetts is subject only to the CAIR's ozone-season NO_x trading program. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NO_x and 2010 for SO_2 and more stringent caps going into effect in 2015. In July 2008, the D.C. Circuit in *State of North Carolina v. Environmental Protection Agency* issued an opinion that would have vacated the CAIR. Various parties filed requests for rehearing with the D.C. Circuit and in December 2008, the D.C. Circuit issued a second opinion in which it granted rehearing only to the extent that it remanded the case to the EPA without vacating the CAIR.

In August 2011, the EPA finalized the CSAPR, which was intended to replace the CAIR starting in 2012. In September 2011, we and others asked the D.C. Circuit to stay and vacate the CSAPR because, among other reasons, the rule circumvents the state implementation plan process expressly provided for in the Clean Air Act, affords affected parties no time to install compliance equipment before the compliance period starts and includes numerous material changes from the proposed rule, which deprived parties of an opportunity to provide comments. In December 2011, the court ordered the EPA to stay implementation of the CSAPR and to keep CAIR in place until the court rules on the legal deficiencies alleged with respect to the CSAPR. The CSAPR addresses interstate transport of emissions of NO_x and SO_2. The CSAPR establishes limitations on NO_x and/or SO_2 emissions from electric generating units that are (i) greater than 25 megawatts and (ii) located in 28 states (in the eastern half of the United States) that the EPA determined contribute significantly to nonattainment in other states, or to interfere with maintenance in other states, of one or more of three NAAQS: (a) the annual NAAQS for fine particulate matter ($PM_{2.5}$) promulgated in 1997; (b) the "24-hour" NAAQS for $PM_{2.5}$ promulgated in 2006 and (c) the ozone NAAQS promulgated in 1997. The CSAPR creates

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"emission budgets" for each of the covered states and allocates emissions allowances (denominated in tons of emissions) to each of the 28 states regulated under the CSAPR.

Under the CSAPR program, the EPA established new allowances for all of the new CSAPR programs and did not permit any carryover of Acid Rain Program or CAIR allowances into the CSAPR trading programs. As a result, the NO_x allowances from the CAIR program would not have been used. Accordingly, we thought that the CAIR NO_x allowances would have no value after 2011. Similarly, the SO_2 allowances used for compliance in the CAIR program (which used the already existing Acid Rain Program allowances that would have continued to be useable for compliance with the Acid Rain Program) would not have been usable for compliance with the CSAPR SO_2 program and we thought they would have negligible value after 2011. As a result of the CSAPR, we recorded impairment losses during 2011 of $133 million for the write-off of excess NO_x and SO_2 emissions allowances. See note 5 to our consolidated financial statements.

We expect that if the CSAPR stay is lifted it will result in reduced generation volumes from uncontrolled coal-fired plants, increased generation from gas-fired plants, increased market power prices and increased emissions costs offset by allocated allowances. The effect of the CSAPR on our adjusted EBITDA depends on the price of the emissions allowances, liquidity in the emissions allowances markets and whether we choose to monetize the allowances. Even if the CSAPR becomes effective at some point, our planned deactivations in response to MATS are expected to mitigate the CSAPR effect starting in the second half of the decade.

Maryland Healthy Air Act. The Maryland Healthy Air Act was enacted in 2006 and required reductions in SO_2, NO_x and mercury emissions from large coal-fired power facilities. The state law also required Maryland to join the RGGI, which is discussed below. The Maryland Healthy Air Act and the regulations adopted by MDE to implement that act impose limits for (a) emissions of NO_x in 2009 with further reductions in 2012 (including sublimits during the Ozone Season) and (b) emissions of SO_2 in 2010 with further reductions in 2013. The Maryland Healthy Air Act also imposes restrictions on emissions of mercury beginning in 2010 with further reductions in 2013. The Maryland Healthy Air Act imposes fixed limits and owners of power facilities may not exceed these fixed limits by purchasing emissions allowances to comply.

We installed scrubbers at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we installed SCR systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto-catalytic reduction system at the other Chalk Point coal-fired unit. We also installed SNCR systems at the three Dickerson coal-fired units. The control equipment we have installed allows our Maryland generating facilities to comply with (a) the first phase of the CAIR without having to purchase emissions allowances and (b) all of the requirements of the Maryland Healthy Air Act.

In 2009, we completed installation of the scrubbers. We expect to invest approximately $1.674 billion in capital expenditures, of which $1.591 billion had been invested at December 31, 2011, to comply with the requirements for SO_2, NO_x and mercury emissions under the Maryland Healthy Air Act. In July 2007, we entered into an agreement with Stone & Webster for EPC services relating to the installation of the scrubbers described above. The cost under the agreement was approximately $1.1 billion and is a part of the $1.674 billion described above. See note 16 to our consolidated financial statements.

New Jersey. In April 2009, the NJDEP finalized a regulation requiring a two-phase reduction in NO_X emissions from combustion turbines in New Jersey. Phase I requires reductions during high electricity demand days and runs from May 2009 through 2014. Under our compliance plan, we operate enhanced NO_x controls at our Shawville, Pennsylvania generating facility (upwind from New Jersey) on high energy demand days. Phase II requires the installation of SCRs at our Gilbert, Sayreville and Werner generating facilities by May 1, 2015. We expect to incur capital expenditures of approximately

$129 million to $151 million, primarily during 2012 to 2015, in connection with our Phase II control plan. As discussed above in "Business Segments Western PJM/MISO Segment," we plan to place the coal-fired units at the Shawville facility in long-term protective layup in April 2015.

MATS. In February 2012, the EPA promulgated emission standards for HAPs from coal- and oil-fired units. The EPA established limits for mercury, non-mercury metals, certain organics and acid gases, which limits must be met beginning in April 2015. These limits are referred to as the MACT standards and they (a) will require us as a condition of continuing to operate to add and operate some additional emissions control equipment at some of our facilities, the cost of which will be significant and (b) will result in the shutdown or retirement of some coal-fired facilities, including some of ours, for which current and forecasted market conditions do not justify the required capital expenditures. See "Business Segments" above for a discussion of coal-fired generating facilities that we expect to deactivate between 2012 and 2015. We expect that higher earnings from price increases resulting from industry retirements will more than offset reduced earnings from our unit deactivations. We plan to upgrade the FGD and invest in an SCR at our Conemaugh generating facility by April 2015. Based on our 16.45% interest in Conemaugh, our net share of these capital expenditures is expected to be between $93 million and $102 million and will occur primarily during 2012 to 2015.

New Source Review Enforcement Initiative. The EPA and various states are investigating compliance of coal-fired electric generating facilities with the pre-construction permitting requirements of the Clean Air Act known as "new source review." In the past decade, the EPA has made information requests for our Avon Lake, Chalk Point, Cheswick, Conemaugh, Dickerson, Elrama, Keystone, Morgantown, New Castle, Niles, Portland, Potomac River, Shawville and Titus generating facilities. We are corresponding or have corresponded with the EPA regarding all of these requests. If a violation is determined to have occurred at any of the facilities, our subsidiary owning or leasing the facilities may be responsible for the cost of purchasing and installing emissions control equipment, the cost of which may be material. Several of our generating facilities already have installed a variety of emissions control equipment. If such a violation is determined to have occurred after our subsidiaries acquired or leased the facilities or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the facility at issue could also be subject to fines and penalties by the state or federal government for the period after its acquisition or lease of the facility, the cost of which may be material, although applicable bankruptcy law may bar such liability for the Chalk Point, Dickerson, Morgantown and Potomac River generating facilities for periods prior to January 3, 2006, when the Plan became effective. See note 16 to our consolidated financial statements.

Regulation of Greenhouse Gases. Concern over climate change has led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions, especially CO_2.

RGGI. RGGI is a multi-state initiative in the Eastern PJM and Northeast outlining a cap-and-trade program to reduce CO_2 emissions from electric generating units with capacity of 25 MW or greater. The RGGI program calls for signatory states, which include Maryland, Massachusetts, New Jersey (through 2011) and New York, to stabilize CO_2 emissions to an established baseline from 2009 through 2014, followed by a 2.5% reduction each year from 2015 through 2018. Each of those states promulgated regulations implementing the RGGI. New Jersey withdrew from the RGGI at the end of 2011.

Complying with the RGGI could have a material adverse effect upon our operations and our operating costs, depending upon the availability and cost of emissions allowances and the extent to which such costs may be offset by higher market prices to recover increases in operating costs caused by the RGGI. As contemplated in a memorandum of understanding among the participating states, Regional Greenhouse Gas Initiative, Inc. is comprehensively reviewing the program, which may cause

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the participating states to change the manner in which the program is administered and may increase our cost to comply.

During 2011, we produced approximately 13.6 million tons of CO_2 at our Maryland, Massachusetts, New Jersey and New York generating facilities for a total cost of $25 million under the RGGI. In 2012, we expect to produce approximately 12.4 million tons of CO_2 at our Maryland, Massachusetts and New York generating facilities. The RGGI regulations required those facilities to obtain allowances to emit CO_2 beginning in 2009. Annual allowances generally were not granted to existing sources of such emissions. Instead, allowances have been made available for such facilities by purchase through periodic auctions conducted quarterly or through subsequent purchase from a party that holds allowances sold through a quarterly auction.

AB 32. In California, emissions of greenhouse gases are governed by AB 32, which requires that statewide greenhouse gas emissions be reduced to 1990 levels by 2020. In December 2008, the CARB approved a Scoping Plan for implementing AB 32. The Scoping Plan requires that the CARB adopt a cap-and-trade regulation by January 2011 and that the cap-and-trade program begin in 2012. In March 2011, a California superior court judge enjoined the implementation of the cap-and-trade program and related Scoping Plan measures until the CARB remedies various procedural flaws related to the CARB's environmental review of the Scoping Plan under the California Environmental Quality Act. A state appellate court stayed the injunction, allowing the CARB to continue to develop the final cap-and-trade regulation. In October 2011, the CARB adopted these final cap-and-trade regulations with an initial compliance period of 2013-2014 for electric utilities and large industrial facilities. In December 2011, the superior court judge affirmed that the CARB remedied the flaws in its environmental review of the Scoping Plan. Our California generating facilities will be required to comply with the cap-and-trade regulations and related rules when they go into effect. The recently adopted cap-and-trade regulation and any other plans, rules and programs approved to implement AB 32 could adversely affect the costs of operating the facilities. However, in accordance with our tolling agreements for the Northern California generating facilities, we would pass any applicable costs through to the counterparties. We have hedged some of the output of our facilities with structures other than tolling agreements. With these hedges we retain some limited exposure to costs associated with the cap-and-trade regulation.

Pennsylvania Climate Change Act. In July 2008, the Pennsylvania Climate Change Act was adopted. This legislation requires development of reports of the effects of climate change in Pennsylvania and potential economic opportunities resulting from mitigation strategies. It requires development of an annual state-level greenhouse gas emissions inventory and baseline, a voluntary registry, and establishment of cost-effective state-level strategies for reducing or offsetting greenhouse gases. The Climate Change Advisory Committee established by the Act published a Climate Change Action Plan in December 2009. The plan includes numerous recommendations to reduce 2020 greenhouse gas emissions in the state by 30 percent below 2000 levels. Recommendations affecting fossil power generation are carbon capture and sequestration at selected coal-fired units and minimum efficiency improvements. The plan also recommends greenhouse gas performance standards for new power plants.

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Massachusetts Climate Protection Act. In August 2008, Massachusetts adopted the Climate Protection Act, which establishes a program to reduce greenhouse gas emissions significantly over the next 40 years. Under the Climate Protection Act, the MADEP has established a reporting and verification system for statewide greenhouse gas emissions, including emissions from generating facilities producing all electricity consumed in Massachusetts, and determined the state's greenhouse gas emissions level in 1990. Under the Climate Protection Act, the MAEEA is to establish statewide greenhouse gas emissions limits effective beginning in 2020 that will reduce such emissions from the 1990 level by a range of 10% to 25% beginning in 2020, with the reduction increasing to 80% below the 1990 level by 2050. In setting these limits, the MAEEA is to consider the potential costs and benefits of various reduction measures, including emissions limits for electric generating facilities, and may consider the use of market-based compliance mechanisms. A violation of the emissions limits established under the Climate Protection Act may result in a civil penalty of up to $25,000 per day. Implementation of the Climate Protection Act could have a material adverse effect on how we operate our Massachusetts generating facilities and the costs of operating those facilities. In December 2010, the MAEEA established a limit for 2020 that is 25% less than the 1990 level.

Maryland Greenhouse Gas Act. In April 2009, the Maryland General Assembly passed the Maryland Greenhouse Gas Act, which became effective in October 2009. The Maryland Greenhouse Gas Act requires a reduction in greenhouse gas emissions in Maryland by 25% from 2006 levels by 2020. However, this provision of the Maryland Greenhouse Gas Act is only in effect through 2016 unless a subsequent statutory enactment extends its effective period. Under the Maryland Greenhouse Gas Act, the MDE plans to complete its proposed implementation plan in early 2012 to achieve these reductions and to adopt a final plan by the end of 2012.

Federal Rules Regarding CO_2. In light of the United States Supreme Court ruling in *Massachusetts v. EPA* that greenhouse gases fit within the Clean Air Act's definition of "air pollutant," the EPA has proposed and promulgated regulations regarding the emission of greenhouse gases. In September 2009, the EPA issued a rule that requires owners of facilities in many sectors of the economy, including power generation, to report annually to the EPA the quantity and source of greenhouse gas emissions released from those facilities. In addition to this reporting requirement, the EPA has promulgated several rules that address greenhouse gas emissions. In December 2009, under a portion of the Clean Air Act that regulates vehicles, the EPA determined that elevated concentrations of greenhouse gases in the atmosphere endanger the public's health and welfare through their contribution to climate change (Endangerment Finding). In April 2010, the EPA finalized a rule to regulate greenhouse gases from vehicles beginning in model year 2012 (Vehicle Rule). In April 2010, the EPA also issued its "Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs" (Tailoring Rule), which addresses the scope of pollutants subject to certain permitting requirements under the Clean Air Act as well as when such requirements become effective. The EPA has stated that, because of the vehicle rule, emissions of greenhouse gases from new stationary sources such as power plants and from major modifications to such sources are subject to certain Clean Air Act permitting requirements as of January 2011. These permitting requirements require such sources to use "best available control technology" to limit their greenhouse gases. Legal challenges to the Endangerment Finding, the Vehicle Rule and the Tailoring Rule have been consolidated and are pending review. The additional substantive requirements under the Clean Air Act that may apply or may come to apply to stationary sources such as power plants are not clear at this time.

In December 2010, the EPA announced that it was starting the process of developing regulations under the New Source Performance Standard section of the Clean Air Act that would affect new and existing fossil-fueled generating facilities. The EPA intends to propose regulations regarding new units in early 2012 and expects to finalize such regulations by late 2012.

In addition to the state and regional regulatory matters described above, over the last several years various bills have been proposed in Congress to govern CO_2 emissions from generating facilities,

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including the creation of a cap-and-trade system that would require us to purchase allowances for some or all of the CO_2 emitted by our generating facilities. If CO_2 regulation becomes more stringent, we expect the demand for natural gas and/or renewable sources of electricity will increase over time. Although we expect that market prices for electricity would increase following such regulation and would allow us to recover a portion of the cost of these allowances, we cannot predict with any certainty the actual increases in costs such regulation could impose upon us or our ability to recover such cost increases through higher market rates for electricity, and such regulation could have a material adverse effect on our consolidated statements of operations, financial position and cash flows. Although it is possible that Congress will take action to regulate greenhouse gas emissions, we do not think this is likely to occur in the near term. The form and timing of any final legislation will be influenced by political and economic factors and is uncertain at this time. Implementation of a CO_2 cap-and-trade program in addition to other emission control requirements could increase the likelihood of retirements of coal-fired generating facilities. During 2011, we produced approximately 33.5 million tons of CO_2 at our generating facilities. We expect to produce approximately 27.9 million total tons of CO_2 at our generating facilities in 2012.

Water Regulations

Clean Water Act. We are required under the Clean Water Act to comply with intake and discharge requirements, requirements for technological controls and operating practices. To discharge water, we generally need permits required by the Clean Water Act. Such permits typically are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to impose additional and more stringent requirements or limitations in the future. This is particularly the case for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act (the 316(b) regulations). In April 2011, the EPA proposed a 316(b) rule that would apply to virtually all existing facilities, including power plants that use cooling water intake structures to withdraw water from waters of the United States. That proposal would impose national standards for reducing mortality for larger, impingeable-sized organisms. It would require permit writers to establish controls for smaller, entrainable-sized organisms on a site-specific basis, taking into account a variety of factors, including costs and benefits. The final rule may differ from the proposal as a result of the public comment process. Until the EPA issues the final rule, which it has committed to do by July 2012, there is significant uncertainty regarding what technologies or other measures will be needed to satisfy section 316(b) regulations.

The EPA also is in the process of updating its technology-based regulations regarding discharges from power plants. The EPA has collected information from numerous power plants to inform this rulemaking. The new standards have not yet been proposed. Accordingly, we cannot predict their effect on our business.

Once-Through Cooling. In October 2010, the California State Water Resources Control Board's Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Once-Through Cooling Policy) became effective. Compliance options for our affected generating units include transitioning to a closed-cycle cooling system, retiring, or submitting an alternative plan that meets equivalent mitigation criteria. The specified compliance date for our Pittsburg and Contra Costa generating facilities is December 31, 2017; and for our Mandalay and Ormond Beach generating facilities the date is December 31, 2020. We will retire the Contra Costa generating facility in May 2013, subject to regulatory approvals. Subject to market prices, we expect to invest between $17 million and $20 million in capital expenditures during 2018 and 2019 at our Mandalay and Ormond Beach generating facilities for variable speed drive pumps. However, we will continue to analyze compliance options for our Pittsburg, Mandalay and Ormond Beach generating facilities. For certain of our California generating facilities the Once-Through Cooling Policy could have a material adverse effect on how we operate those facilities and the costs of operating those facilities. In October 2010, we and several other companies jointly filed a lawsuit in California superior court challenging the California State Water Resources Control Board's issuance of the Once-Through Cooling Policy on various procedural and substantive grounds. The lawsuit seeks a writ directing the California State Water Resources Control Board to vacate and set aside approval of the Once-Through Cooling Policy. A hearing on the merits is scheduled for March 2012.

Endangered Species Act. Our use of water from the Sacramento-San Joaquin Delta at the Contra Costa and Pittsburg generating facilities potentially affects certain fish species protected under the federal Endangered Species Act. We therefore must maintain authorization to engage in operations that could result in a take of (i.e., cause harm to) fish of the protected species. In September 2007, the Delta Noticing Parties notified us of their intent to sue alleging that we violated, and continue to violate, the federal Endangered Species Act because we operate the Contra Costa and Pittsburg generating facilities. In October 2007, the United States Fish and Wildlife Service, the National Marine Fisheries Service and the Army Corps of Engineers initiated a process that reviewed the environmental effects of our water usage, including effects on the protected species of fish. They also clarified that we continued to be authorized to take four species of fish protected under the federal Endangered Species Act. In May 2009, the Coalition for a Sustainable Delta, Kern County Water Agency and an individual sent a new notice of intent to sue to the Army Corps of Engineers alleging that the Army Corps of Engineers had violated the federal Endangered Species Act by issuing permits related to the operation of the Contra Costa and Pittsburg generating facilities. We dispute the allegations made by the Delta Noticing Parties and those made in the May 2009 notice.

In February 2010, we entered into a settlement agreement with the Delta Noticing Parties, the parties to the May 2009 notice of intent to sue, and the Army Corps of Engineers. The settlement agreement provides for the Delta Noticing Parties and the parties to the May 2009 notice of intent to sue to withdraw the two notices of intent to sue and to release all claims described in those notices. The settlement agreement obligated us to monitor entrainment and impingement of aquatic species caused by the operation of our generating facilities. We have completed the monitoring activities. The settlement agreement requires the Army Corps of Engineers to use its best efforts to conclude ongoing consultations with the United States Fish and Wildlife Service and the National Marine Fisheries Service regarding the environmental effects of our water usage in a timely manner and allows the Delta Noticing Parties and the parties to the May 2009 notice of intent to sue to issue new notices of intent to sue if such consultations were not completed by October 31, 2011. The National Marine Fisheries Service completed its consultation in February 2012, and consultation with the United States Fish and Wildlife Service is pending. We have apprised the Delta Noticing Parties of the status of such consultations.

Kendall NPDES and Surface Water Discharge Permit. In September 2006, the EPA issued an NPDES renewal permit for the Kendall cogeneration facility. The same permit was concurrently issued by the MADEP as a state SWD permit, and was accompanied by MADEP's earlier issued water quality certificate under section 401 of the Clean Water Act. These permits sought to impose new temperature limits at various points in the Charles River, an extensive temperature, water quality and biological monitoring program and a requirement to develop and install a barrier net system to reduce fish impingement and entrainment. The provisions regulating the thermal discharge could have caused substantial curtailments of the operations of the Kendall generating facility. We appealed the permits in three proceedings: (a) appeal of the NPDES permit to the EPA's Environmental Appeals Board; (b) appeal of the SWD permit to the MADEP; and (c) appeal of the water quality certification to the MADEP. The effect of the permits was stayed pending the outcome of these appeals. In March 2008, the EPA and the MADEP issued a draft permit modification to address the 316(b) provisions of the permit that would have required modifications to the intake structure for the Kendall generating facility to add fine and coarse mesh barrier exclusion technologies and a mechanism to sweep organisms away from the intake structure through an induced water flow. In May 2008, we submitted comments on the draft permit modification objecting to the new requirements. In December 2008, the EPA and the MADEP issued final permit modifications to address the 316(b) regulations. Those final permit modifications did not substantially modify the requirements proposed in the draft modifications, and in February 2009, we filed an appeal of those modifications.

In October 2010, we submitted a permit modification request to the EPA and MADEP that requested modification of the 2006 permits (as previously modified in 2008) to reflect revised permit terms agreed upon by us, the EPA and MADEP as part of a settlement of the permit renewal proceedings pending before the EPA and MADEP. The settlement contemplates that an additional steam pipeline will be installed across the Charles River to allow us to make additional steam sales to Trigen-Boston Energy Corporation in Boston and that we will install a back pressure steam turbine and air-cooled condenser at the Kendall generating facility. This new pipeline and equipment once operational, would allow us to reduce significantly the use of water from the Charles River. In October 2010, the EPA and MADEP issued the proposed revised permits (the 2010 Kendall Permits) as draft permit modifications for public comment. In December 2010, the EPA and MADEP issued final permits that became effective in February 2011. The 2010 Kendall Permits will limit us to drawing no more than 3.2 million gallons of water per day from the river under normal operations, impose temperature limits similar to the 2006 permits, and require monitoring of temperatures at various points in the river when the Kendall generating facility is discharging water to the river. Because river water will no longer be used for once-through cooling under normal operations once the new pipeline and equipment have been installed, we expect the 2010 Kendall Permits to impose significantly less risk that operations of the facility would have to be curtailed to maintain compliance with the temperature limits. As part of our settlement with the EPA and MADEP, the EPA and MADEP issued administrative orders that provide deadlines for achieving certain milestones associated with the installation of the back pressure steam turbine, air-cooled condenser and the new steam pipeline. The administrative orders allow us to defer the new limit on the amount of river water used by the Kendall cogenerating facility and the new temperature limits imposed by the 2010 Kendall Permits until installation has been completed of the new pipeline, the back pressure steam turbine, and the air-cooled condenser, which is expected to occur in 2014. Capital expenditures for this project are expected to be between $32 million and $35 million primarily during 2012 to 2014.

Canal NPDES and SWD Permit. In August 2008, the EPA issued an NPDES renewal permit for the Canal generating facility. The same permit was concurrently issued by MADEP as a state SWD permit, and was accompanied by MADEP's earlier water quality certificate under section 401 of the Clean Water Act. The new permit imposes a requirement on us to install closed cycle cooling or an alternative technology that will reduce the entrainment of marine organisms by the Canal generating facility to levels equivalent to what would be achieved by closed cycle cooling. We appealed the NPDES permit to the EPA's Environmental Appeals Board and appealed the surface water discharge and the water quality certificate to the MADEP. In December 2008, the EPA requested a stay to the appeal proceedings and withdrew provisions related to the closed cycle cooling requirements. The EPA has re-noticed these provisions as draft conditions for additional public comment. We filed comments in January 2009, stating that installing closed cycle cooling at the Canal generating facility was not justified and that without some cost-recovery mechanism the cost would make continued operation of the facility uneconomic. While the appeals of the renewal permit are pending, the effect of any contested permit provisions is stayed and the Canal generating facility will continue to operate under its current NPDES permit. We are unable to predict the outcome of this proceeding.

Shawville NPDES Permit Appeal. In August 2010, the PADEP issued a renewed NPDES permit effective September 2010 that contains discharge limits for the leased Shawville generating facility that require installation of cooling towers or reduction in plant operation by September 1, 2013. The Pennsylvania Fish & Boat Commission and we appealed the permit to the Pennsylvania Environmental Hearing Board. We have recently entered into an agreement that resulted in a revised permit that delays this requirement until July 2015. In February 2012, the Sierra Club appealed the revised permit to the Pennsylvania Environmental Hearing Board. As discussed above in "Business Segments Western PJM/MISO Segment," we plan to place the coal-fired units at the Shawville generating facility in long-term protective layup in April 2015.

NPDES and State Pollutant Discharge Elimination System Permit Renewals. In addition to the various NPDES proceedings described above, proceedings are currently pending for renewal of the NPDES or state pollutant discharge elimination system permits at many of our generating facilities and ash disposal sites. In general, the EPA and the state agencies responsible for implementing the provisions of the Clean Water Act applicable to the intake of water and discharge of effluent by electric generating facilities have been making the requirements imposed upon such facilities more stringent over time. With respect to each of these permit renewal proceedings, the permit renewal proceeding could take years to resolve and the agency or agencies involved could impose requirements upon the entity owning the facility that require significant capital expenditures, limit the times at which the facility can operate, or increase operations and maintenance costs materially.

Byproducts, Wastes, Hazardous Materials and Contamination

Our facilities are subject to laws and regulations governing waste management. The federal Resource Conservation and Recovery Act of 1976 (and many analogous state laws) contains comprehensive requirements for the handling of solid and hazardous wastes. The generation of electricity produces non-hazardous and hazardous materials, and we incur substantial costs to store and dispose of waste materials. The EPA and the states in which we operate coal-fired units may develop new regulations that impose additional requirements on facilities that store or dispose of materials remaining after the combustion of fossil fuels, including coal ash. If so, we may be required to change our current waste management practices at some facilities and incur additional costs.

In June 2010, the EPA proposed two alternatives for regulating byproducts of coal combustion (e.g., ash and gypsum) under the federal Resource Conservation and Recovery Act of 1976. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would be regulated as "special wastes" in a manner similar to the regulation of hazardous waste with an exception for beneficial reuse of these byproducts. The second alternative would impose significantly more stringent requirements on and increase materially the cost of disposal of coal combustion byproducts.

We acquired our Contra Costa, Pittsburg and Potrero generating facilities from PG&E. All three have areas of soil and groundwater contamination. In 1998, prior to our acquisition of those facilities from PG&E, consultants for PG&E conducted soil and groundwater investigations at those facilities which revealed contamination. The consultants conducting the investigation estimated the aggregate cleanup costs at those facilities could be as much as $60 million. Pursuant to the terms of the Purchase and Sale Agreement with PG&E, PG&E has responsibility for the containment or capping of all soil and groundwater contamination and the disposition of up to 60,000 cubic yards of contaminated soil from the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E's consultants in 1998 at the Contra Costa and Pittsburg generating facilities, before we purchased those facilities in 1999. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil from the Potrero generating facility. We are not aware of soil or groundwater conditions at our Contra Costa, Pittsburg and Potrero generating facilities for which we expect remediation costs to be material that are not the responsibility of other parties.

In 2008, we closed and then demolished the Lovett generating facility in New York. Pursuant to an agreement with the New York State Department of Environmental Conservation in 2009, we assessed the environmental condition of the property. During late 2011, the New York State Department of Environmental Conservation indicated the site characterization work was acceptable and requested we

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engage in an assessment of remedial alternatives for issues identified at the site. We are in the process determining these alternatives; however, we have not completed this process.

We are responsible for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. We recorded the estimated long-term liability for the remediation costs of $6 million at December 31, 2011. See notes 1 and 16 to our consolidated financial statements.

See note 16 to our consolidated financial statements regarding discussion of storm damage and remediation at our Brandywine ash disposal site.

Other. As a result of their age, many of our plants contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. We think we properly manage and dispose of such materials in compliance with state and federal rules.

Additionally, CERCLA, also known as the Superfund law, establishes a federal framework for dealing with the cleanup of contaminated sites. Many states have enacted similar state superfund statutes as well as other laws imposing obligations to investigate and clean up contamination. These laws impose clean up and restoration liability on owners and operators of plants from or at which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances. We do not think we have any material liabilities or obligations under CERCLA or similar state laws.

Employees

At February 10, 2012, we employed 3,103 people, which included 2,262 employees at our generating facilities, 400 employees at our regional offices and 441 employees at our corporate

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headquarters in Houston, Texas. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Eastern PJM Region			
IBEW Local 327	New Jersey	16	10/31/2016
IBEW Local 1900	Maryland and Virginia	470	6/1/2015
Western PJM/MISO Region			
IBEW Local 29	Pennsylvania	127	9/30/2014
IBEW Local 459	Pennsylvania	526	5/14/2014
IBEW Local 777	Pennsylvania	124	4/30/2012
UWUA Local 140	Pennsylvania	28	10/31/2013
UWUA Local 270	Avon Lake, Ohio	50	4/30/2013
UWUA Local 270	Niles, Ohio	29	3/31/2014
California			
IBEW Local 47	California	23	3/31/2013
IBEW Local 1245[(1)]	California	84	10/31/2013
Other Operations			
IBEW Local 66	Texas	12	12/31/2015
IBEW Local 503	New York	31	4/30/2013
UWUA Local 369	Cambridge, Massachusetts	29	2/28/2013
UWUA Local 369	Sandwich, Massachusetts	26	10/30/2014
Total		1,575	

(1) As a result of the shutdown of the Potrero generating facility in February 2011, we downsized the bargaining unit workforce consistent with an agreement negotiated with Local 1245.

We intend to negotiate the renewal of the collective bargaining agreement expiring in 2012 and do not anticipate any disruptions to our operations. To mitigate and reduce the risk of disruption during labor negotiations, we engage in contingency planning for operation of our generating facilities to the extent possible during an adverse collective action by one or more of our unions.

Available Information

Our principal offices are at 1000 Main Street, Houston, Texas 77002 (832-357-7000). The following information is available free of charge on our website (http://www.genon.com):

- Our corporate governance guidelines and standing board committee charters;
- Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports; and
- Our code of ethics and business conduct.

You can request a free copy of these documents by contacting our investor relations department. It is our intention to disclose amendments to, or waivers from, our code of ethics and business conduct on our website. No information on our website is incorporated by reference into this Form 10-K. In addition, our annual, quarterly and current reports are available on the SEC's website at (http://www.sec.gov) or at its public reference room: 100 F Street, NE, Room 1580, Washington, D.C. 20549 (1-800-SEC-0330).

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Item 1A. *Risk Factors.*

We are subject to the following factors that could have a material adverse effect on our future performance, results of operations, financial condition and cash flows. In addition, such factors could affect our ability to service our indebtedness and other obligations, our ability to raise capital and our future growth opportunities. Also, see "Cautionary Statement Regarding Forward-Looking Information" on page vi, "Business" in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this Form 10-K.

Risks Related to the Operation of our Business

Our financial results are unpredictable because most of our generating facilities operate without long-term power sales agreements, and our revenues and results of operations depend on market and competitive forces that are beyond our control.

We provide energy, capacity, ancillary and other energy services from our generating facilities in a variety of markets and to bi-lateral counterparties, including participating in wholesale energy markets, entering into tolling agreements, sales of resource adequacy and participation in capacity auctions. Our revenues from selling capacity are a significant part of our overall revenues. We are not guaranteed recovery of our costs or any return on our capital investments through mandated rates.

The market for wholesale electric energy and energy services reflects various market conditions beyond our control, including the balance of supply and demand, transmission congestion, our competitors' marginal and long-term costs of production, the price of fuel, and the effect of market regulation. The price at which we can sell our output may fluctuate on a day-to-day basis, and our ability to transact may be affected by the overall liquidity in the markets in which we operate. These markets remain subject to regulations that limit our ability to raise prices during periods of shortage to the degree that would occur in a fully deregulated market. In addition, unlike most other commodities, electric energy can be stored only on a very limited basis and generally must be produced at the time of use. As a result, the wholesale power markets are subject to substantial price fluctuations over relatively short periods of time and can be unpredictable. For further discussion, see "Business Competitive Environment."

Our revenues, results of operations and cash flows are influenced by factors that are beyond our control, including those set forth above, as well as:

- the failure of market regulators to develop and maintain efficient mechanisms to compensate merchant generators for the value of providing capacity needed to meet demand;
- actions by regulators, ISOs, RTOs and other bodies that may artificially modify supply and demand levels and prevent capacity and energy prices from rising to the level necessary for recovery of our costs, our investment and an adequate return on our investment;
- legal and political challenges to or changes in the rules used to calculate capacity payments in the markets in which we operate or the establishment of bifurcated markets, incentives, other market design changes or bidding requirements that give preferential treatment to new generating facilities over existing generating facilities or otherwise reduce capacity payments to existing generating facilities;
- the ability of wholesale purchasers of power to make timely payment for energy or capacity, which may be adversely affected by factors such as retail rate caps, refusals by regulators to allow utilities to recover fully their wholesale power costs and investments through rates, catastrophic losses and losses from investments by utilities in unregulated businesses;
- increases in prevailing market prices for fuel oil, coal, natural gas and emissions allowances that may not be reflected in prices we receive for sales of energy;

- increases in electricity supply as a result of actions of our current competitors or new market entrants, including the development of new generating facilities or alternative energy sources that may be able to produce electricity less expensively than our generating facilities and improvements in transmission that allow additional supply to reach our markets;
- increases in credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of future OTC regulations adopted pursuant to the Dodd-Frank Act;
- decreases in energy consumption resulting from demand-side management programs such as automated demand response, which may alter the amount and timing of consumer energy use;
- the competitive advantages of certain competitors, including continued operation of older power facilities in strategic locations after recovery of historic capital costs from ratepayers;
- existing or future regulation of our markets by the FERC, ISOs and RTOs, including any price limitations and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;
- our obligation under any default sharing mechanisms in RTO and ISO markets, such mechanisms exist to spread the risk of defaults by transmission owning companies or other RTO members across all market participants;
- regulatory policies of state agencies that affect the willingness of our customers to enter into long-term contracts generally, and contracts for capacity in particular;
- access to contractors and equipment;
- changes in the rate of growth in electricity usage as a result of such factors as national and regional economic conditions and implementation of conservation programs;
- seasonal variations in energy and natural gas prices, and capacity payments; and
- seasonal fluctuations in weather, in particular abnormal weather conditions.

We expect that higher earnings from price increases resulting from industry retirements will more than offset reduced earnings from our unit deactivations. However, as discussed above, the market for wholesale electric energy and energy services reflects various market conditions beyond our control, including the balance of supply and demand, our competitors' marginal and long-term costs of production, and the effect of market regulation. We cannot ensure that higher earnings or price increases will result from industry retirements of coal-fired generating facilities or that higher earnings from our remaining facilities will offset or more than offset reduced earnings from our facility deactivations.

Changes in the wholesale energy markets or in our generating facility operations as a result of increased environmental requirements could result in impairments or other charges.

If our ongoing evaluation of our business results in decisions to deactivate or dispose of additional facilities, we could have impairments or other charges, including charges relating to the assets of RRI Energy that were recorded at fair values in conjunction with the Merger. These evaluations involve significant judgments about the future. Actual future market prices, project costs and other factors could be materially different from our current estimates. See "Business Segments" above for a discussion of coal-fired generating facilities that we expect to deactivate between 2012 and 2015.

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Our Marsh Landing development project is subject to construction risks and, if we are unsuccessful in addressing those risks, we may not recover our investment in the project or our return on the project may be lower than expected.

Our return on the Marsh Landing development project may be lower than expected if GenOn Marsh Landing does not complete construction of the generating facility by the required completion date under its long-term PPA with PG&E. Should the facility fail to be operational or not perform as required under the terms of the PPA, PG&E may have the right to terminate the PPA. A termination of the PPA would trigger an event of default under the GenOn Marsh Landing credit facility. As there is currently no wholesale capacity market in California, if PG&E were to terminate the PPA, the ability to refinance the project would likely be limited. GenOn Marsh Landing's contingent obligations for delay damages or termination payments under the PPA were $54 million at December 31, 2011, and escalate over the construction period. See note 10 to our consolidated financial statements for discussion of letters of credit issued and surety bonds posted to secure GenOn Marsh Landing's obligations to PG&E and to Kiewit and in connection with the Marsh Landing development project.

We are exposed to the risk of fuel cost volatility because we must pre-purchase coal and oil.

Most of our fuel contracts are at fixed prices with terms of two years or less. Although we purchase coal and oil based on our expected requirements, we still face the risks of fuel price volatility if we require more fuel than we expected.

Our cost of fuel may not reflect changes in energy and fuel prices in part because we must pre-purchase inventories of coal and oil for reliability and dispatch requirements, and thus the price of fuel may have been determined at an earlier date than the price of energy generated from the fuel. Similarly, the price we can obtain from the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs.

We are exposed to the risk of our fuel providers and fuel transportation providers failing to perform.

For our coal-fired generating facilities, we purchase most of our coal from a limited number of suppliers. Because of a variety of operational issues, our coal suppliers may not provide the contractual quantities on the dates specified within our agreements, or the deliveries may be carried over to future periods. Also, interruptions to planned or contracted deliveries to our generating facilities can result from a lack of, or constraints in, coal transportation because of rail, river or road system disruptions, adverse weather conditions and other factors.

If our coal suppliers do not perform in accordance with the agreements, we may have to procure higher priced coal in the market to meet our needs, or higher priced power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. For a discussion of our coal supplier concentration risk, see note 1 to our consolidated financial statements.

For our oil-fired generating facilities, we typically purchase fuel from a limited number of suppliers. If our oil suppliers do not perform in accordance with the agreements, we may have to procure higher priced oil in the market to meet our needs, or higher priced power in the market to meet our obligations. For our gas-fired generating facilities, any curtailments or interruptions on transporting pipelines could result in curtailment of our operations or increased fuel supply costs.

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Operation of our generating facilities involves risks that could result in disruption, curtailment or inefficiencies in our operations.

The operation of our generating facilities involves various operating risks, including, but not limited to:

- the output and efficiency levels at which those generating facilities perform;
- interruptions in fuel supply and quality of available fuel;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether a result of age or otherwise);
- violations of our permit requirements or changes in the terms of, or revocation of, permits;
- releases of pollutants and hazardous substances to air, soil, surface water or groundwater;
- ability to transport and dispose of coal ash at reasonable prices;
- curtailments or other interruptions in natural gas supply;
- shortages of equipment or spare parts;
- labor disputes, including strikes, work stoppages and slowdowns;
- the aging workforce at many of our facilities;
- operator errors;
- curtailment of operations because of transmission constraints;
- failures in the electricity transmission system which may cause large energy blackouts;
- implementation of unproven technologies in connection with environmental improvements; and
- catastrophic events such as fires, explosions, floods, earthquakes, hurricanes or other similar occurrences.

These factors could result in a material decrease, or the elimination of, the revenues generated by our facilities or a material increase in our costs of operations.

We operate in a limited number of markets and a significant portion of our revenues are derived from the PJM market. The effect of adverse developments in our markets, especially the PJM market, may be greater on us than on our more geographically diversified competitors.

Our generating capacity is 57% in PJM, 23% in CAISO, 11% in NYISO and ISO-NE, 8% in the Southeast and 1% in MISO. Approximately 42% and 37% of our realized gross margin during 2011 was attributable to our Eastern PJM and Western PJM/MISO operating segments, respectively. Adverse developments in these regions, especially in the PJM market, may adversely affect us. Further, the effect of such adverse regional developments may be greater on us than on our more geographically diversified competitors.

We are exposed to possible losses that may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement with us, particularly in connection with our non-collateralized power hedges between GenOn Mid-Atlantic and financial institutions.

Non-collateralized power hedges with financial institutions represent 37% of our net notional power position at December 31, 2011. Such hedges are senior unsecured obligations of GenOn

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Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Deterioration in the financial condition of such counterparties could result in their failure to pay amounts owed to us or to perform obligations or services owed to us beyond collateral posted. For a discussion of the GenOn Mid-Atlantic credit concentration risk, see "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A in this Form 10-K.

Our income tax NOL carry forwards could be substantially limited if we experience an ownership change as defined in the IRC.

We have approximately $2.6 billion of federal NOL carry forwards, which we are able to use to offset taxable income in future years. If, however, an "ownership change," as defined in IRC § 382, occurs, the amount of NOLs that could be used in any one year following such ownership change would be substantially limited. In general, an "ownership change" would occur when there is a greater than 50-percentage point increase in ownership of a company's stock by stockholders each of which owns (or is deemed to own under IRC § 382) 5% or more of such company's stock. Given IRC § 382's broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Moreover, while we have a Protective Charter Amendment and a stockholder rights plan in place in an effort to preserve our NOLs, neither measure offers a complete solution and an ownership change could occur. We cannot assure that the Protective Charter Amendment's restriction on acquisitions of our common stock will be enforceable against all our stockholders, and the restriction may be subject to challenge. The stockholder rights plan can only deter, not prevent, an ownership change that would result in the loss of our NOLs. Based on information contained in a shareholder's recent filing made pursuant to SEC Regulation 13G and subsequent inquiries made on the basis of such information, it is possible RRI Energy may have experienced an ownership change as defined above as a result of the Merger. As of this date we have not completed verification of the change and we continue to seek "actual knowledge" with respect to certain facts pertaining to the possible ownership change. Should we determine that RRI Energy had an ownership change at the Merger date, its NOLs would be substantially limited to reflect the requirements of IRC § 382. See notes 7 and 12 to our consolidated financial statements.

Regulated utilities have competitive advantages in wholesale power markets.

We compete with non-utility generators, regulated utilities, and other energy service companies in the sale of our products and services, as well as in the procurement of fuel, fuel transportation and transmission services. We compete primarily on the basis of price and service. Regulated utilities in the wholesale markets generally enjoy a lower cost of capital than we do and often are able to recover fixed costs through regulated retail rates, including, in many cases, the costs of generation, allowing them to build, buy and upgrade generating facilities without relying exclusively on market-clearing prices to recover their investments.

Changes in technology may significantly affect our generating business by making our generating facilities less competitive.

We generate electricity using fossil fuels at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in those technologies, or governmental incentives for renewable energies, will reduce their costs to levels that are equal to or below that of most central station electricity production.

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The expected decommissioning and/or site remediation obligations of certain of our generating facilities may negatively affect our cash flows.

Some of our generating facilities and related properties are subject to decommissioning and/or site remediation obligations that may require material expenditures. Furthermore, laws and regulations may change to impose material additional decommissioning and remediation obligations on us in the future.

Terrorist attacks and/or cyber-attacks may result in our inability to operate and fulfill our obligations, and could result in material repair costs.

As a power generator, we face heightened risk of terrorism, including cyber terrorism, either by a direct act against one or more of our generating facilities or an act against the transmission and distribution infrastructure that is used to transport our power. Although our entire industry is exposed to these risks, our generating facilities and the transmission and distribution infrastructure located in the PJM market are particularly at risk because of the proximity to major population centers, including governmental and commerce centers.

We rely on information technology networks and systems to operate our generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information related to our employees, vendors and counterparties. Confidential information includes banking, vendor, counterparty and personal identity information.

Systemic damage to one or more of our generating facilities and/or to the transmission and distribution infrastructure could result in our inability to operate in one or all of the markets we serve for an extended period of time. If our generating facilities are shut down, we would be unable to respond to the ISOs and RTOs or fulfill our obligations under various energy and/or capacity arrangements, resulting in lost revenues and potential fines, penalties and other liabilities. Pervasive cyber-attacks across our industry could affect the ability of ISOs and RTOs to function in some regions. The cost to restore our generating facilities after such an occurrence could be material.

Our operations are subject to hazards customary to the power generating industry. We may not have adequate insurance to cover all of these hazards.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of high-speed rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks (such as earthquake, flood, storm surge, lightning, hurricane, tornado and wind), hazards (such as fire, explosion, collapse and machinery failure) are inherent risks in our operations. We are also susceptible to terrorist attacks, including cyber-attacks, against our generating facilities or the transmission and distribution infrastructure that is used to transport our power. These hazards can cause significant injury to personnel or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We do not maintain specialized insurance for possible liability resulting from a cyber-attack on our systems that may shut down all or part of the transmission and distribution system. However, we maintain an amount of insurance protection that we consider adequate and customary for merchant power producers. We cannot assure that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject.

Lawsuits, regulatory proceedings and tax proceedings could adversely affect our future financial results.

From time to time, we are named as a party to, or our property is the subject of, lawsuits, regulatory proceedings or tax proceedings. We are currently involved in various proceedings which involve highly subjective matters with complex factual and legal questions. Their outcome is uncertain. Any claim that is successfully asserted against us could require significant expenditures by us. Even if we prevail, any proceedings could be costly and time-consuming, could divert the attention of our management and key personnel from our business operations and could result in adverse changes in our insurance costs. See notes 7 and 16 to our consolidated financial statements.

We depend on the skills, experience and efforts of our people.

The successful execution of our business strategy is dependent on the skills, experience and efforts of our people. The loss of one or more members of our senior management or employees with critical skills could adversely affect our future business, financial condition, and operating results if we were unable to secure the talent that we feel is needed.

If we acquire or develop additional facilities, dispose of existing facilities or combine with other businesses, we may incur additional costs and risks.

We may seek to purchase or develop additional facilities, dispose of existing facilities, or combine with other businesses. There is no assurance that these efforts will be successful. In addition, these activities involve risks and challenges, including identifying suitable opportunities, obtaining required regulatory and other approvals, integrating acquired or combined operations with our own, and increasing expenses and working capital requirements. Furthermore, in any sale, we may be required to indemnify a purchaser against liabilities. To finance future acquisitions, we may be required to issue additional equity securities or incur additional debt. Obtaining such additional financing is dependent on numerous factors, including general economic and capital market conditions, credit availability from financial institutions, the covenants in our debt agreements, and our financial performance, cash flow and credit ratings. We cannot make any assurances that we would be able to obtain such additional financing on commercially reasonable terms or at all.

Risks Related to Economic and Financial Market Conditions

We are exposed to systemic risk of the financial markets and institutions and the risk of non-performance of the individual lenders under our undrawn credit facilities.

Maintaining sufficient liquidity in our business for maintenance and operating expenditures, capital expenditures and collateral is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we maintain a revolving credit facility to manage our expected liquidity needs and contingencies. In the event that financial institutions are unwilling or unable to renew our existing revolving credit facility or enter into new revolving credit facilities, our ability to hedge economically our assets or engage in proprietary trading could also be impaired.

We have significant undrawn availability under our revolving credit facility and Marsh Landing credit facility. A significant portion of the Marsh Landing project costs are expected to be funded through drawings under the GenOn Marsh Landing credit facility. The failure of the lenders to perform under our revolving credit facility or the Marsh Landing credit facility could have a material adverse effect on our liquidity and the ability to complete construction of the Marsh Landing facility, respectively.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity" in Item 7 of this Form 10-K and note 6 to our consolidated financial statements.

A negative market perception of our value could impair our ability to raise capital or refinance debt.

A sustained downturn in general economic conditions, including low power and commodity prices, could result in a perceived weakness in our overall financial health. This may result in our stock price remaining at a low level for an extended time, which would impair our ability to access equity markets.

A negative market perception of our value could result in our inability to obtain and maintain an appropriate credit rating. In this event, we may be unable to access debt markets or refinance future debt maturities, or we may be required to post additional collateral to operate our business.

As financial institutions consolidate and operate under more restrictive capital constraints and regulations, including the Dodd-Frank Act, there could be less liquidity in the energy and commodity markets for hedge transactions and fewer creditworthy counterparties.

We hedge economically a substantial portion of our PJM coal-fired baseload generation and certain of our other generation. A significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral, either for initial margin or for securing exposure as a result of changes in power or natural gas prices. Global financial institutions have been active participants in these energy and commodity markets. As global financial institutions consolidate and operate under more restrictive capital constraints and regulations, including the Dodd-Frank Act, there could be less liquidity in the energy and commodity markets, which could have a material adverse effect on our ability to hedge economically and transact with creditworthy counterparties.

The Dodd-Frank Act could materially affect our business, including greater regulation of energy contracts and OTC derivative financial instruments, which could materially and adversely affect our ability to hedge economically our generation and engage in proprietary trading.

The Dodd-Frank Act, which was enacted in July 2010 in response to the global financial crisis, increases the regulation of transactions involving OTC derivative financial instruments. The effect of the Dodd-Frank Act on our business depends in large measure on pending rulemaking proceedings of the CFTC, the SEC and the federal banking regulators. Under the Dodd-Frank Act, entities defined as "swap dealers" and "major swap participants" will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. Although we do not expect our commercial activity to result in our designation as an SD/MSP, as proposed, the "swap dealer" definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. It is possible that the final rule will not offer much clarity and the designation as an SD/MSP could be decided by facts and circumstance tests. The impact of the final regulations, or the uncertainty as to the scope thereof, could have a material adverse effect on our commercial activities and our ability to hedge economically, including decreasing liquidity in the forward commodity markets.

Many of the factors that cause changes in commodity prices are outside our control and may materially increase our cost of producing power or lower the price at which we are able to sell our power.

Our generating business is subject to changes in power prices and fuel and emissions costs, and these commodity prices are influenced by many factors outside our control, including weather, seasonal variation in supply and demand, market liquidity, transmission and transportation inefficiencies, availability of competitively priced alternative energy sources, demand for energy commodities, production of natural gas, coal and crude oil, natural disasters, wars, embargoes and other catastrophic events, and federal, state and environmental regulation and legislation. In addition, significant fluctuations in the price of natural gas may cause significant fluctuations in the price of electricity. Significant fluctuations in commodity prices may affect our financial results and financial position by increasing the cost of producing power and decreasing the amounts we receive from the sale of power.

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Our hedging activities will not fully protect us from fluctuations in commodity prices.

We engage in hedging activities related to sales of electricity and purchases of fuel and emission allowances. The income and losses from these activities are recorded as operating revenues and fuel costs. We may use forward contracts and other derivative financial instruments to manage market risk and exposure to volatility in prices of electricity, coal, natural gas, emissions and oil. The effectiveness of these hedges is dependent upon the correlation between the forward contracts and the other derivative financial instruments used as a hedge and the market risk of the asset or assets being hedged. We cannot provide assurance that these strategies will be successful in managing our price risks, or that they will not result in net losses to us as a result of future volatility in electricity, fuel and emissions markets. Actual power prices and fuel costs may differ from our expectations.

Our hedging activities include natural gas derivative financial instruments that we use to hedge economically power prices for our baseload generation. The effectiveness of these hedges is dependent upon the correlation between power and natural gas prices in the markets where we operate. If those prices are not sufficiently correlated, our financial results and financial position could be adversely affected. See note 4 to our consolidated financial statements and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

Additionally, we expect to have an open position in the market, within our established guidelines, resulting from our proprietary trading and fuel oil management activities. To the extent open positions exist, fluctuating commodity prices can affect our financial results and financial position, either favorably or unfavorably. As a result of these and other factors, we cannot predict the outcome that risk management decisions may have on our business, operating results or financial position. Although management devotes considerable attention to these issues, their outcome is uncertain.

Our policies and procedures cannot eliminate the risks associated with our hedging and proprietary trading activities.

The risk management procedures we have in place may not always be followed or may not always work as planned. If any of our employees were able to violate our system of internal controls, including our risk management policy, and engage in unauthorized hedging and related activities, it could result in significant penalties and financial losses. In addition, risk management tools and metrics such as value at risk, gross margin at risk, and stress testing are partially based on historic price movements. If price movements significantly or persistently deviate from historical behavior, risk limits may not fully protect us from significant losses.

Our hedging, proprietary trading and fuel oil management activities may increase the volatility of our GAAP financial results.

Derivatives from our hedging, proprietary trading and fuel oil management activities are recorded on our balance sheet at fair value pursuant to the accounting guidance for derivative financial instruments. Other than interest rate swaps into which we entered to manage our interest rate risk associated with our GenOn Marsh Landing project financing, none of our other derivatives recorded at fair value is designated as a hedge under this guidance, and changes in their fair values currently are recognized in earnings as unrealized gains or losses. As a result, our GAAP financial results including gross margin, operating income and balance sheet ratios will, at times, be volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. See notes 1 and 4 to our consolidated financial statements.

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Risks Related to Governmental Regulation and Laws

Our costs of compliance with environmental laws are significant and can affect our future operations and financial results.

We are subject to extensive and evolving environmental regulations, particularly in regard to our coal- and oil-fired facilities. Environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require us to make additional facility upgrades or restrict our operations. Failure to comply with environmental requirements could require us to shut down or reduce production at our facilities or create liabilities. We incur significant costs in complying with these regulations and, if we fail to comply, could incur significant penalties. Our cost estimates for environmental compliance are based on existing regulations or our view of reasonably likely regulations, and our assessment of the costs of labor and materials and the state of evolving technologies. Our decision to make these investments is often subject to future market conditions. Changes to the preceding factors, new or revised environmental regulations, litigation and new legislation and/or regulations, as well as other factors, could cause our actual costs to vary outside the range of our estimates, further constrain our operations, increase our environmental compliance costs and/or make it uneconomical to operate some of our facilities. See "Business Segments" above for a discussion of coal-fired generating facilities that we expect to deactivate between 2012 and 2015.

Federal, state and regional initiatives to regulate greenhouse gas emissions could have a material impact on our financial performance and condition. The actual impact will depend on a number of factors, including the overall level of greenhouse gas reductions required under any such regulations, the final form of the regulations or legislation, and the price and availability of emissions allowances if allowances are a part of any final regulatory framework.

We are required to surrender emissions allowances equal to emissions of specific substances to operate our facilities. Surrender requirements may require purchase of allowances, which may be unavailable or only available at costs that would make it uneconomical to operate our facilities.

Certain environmental laws, including CERCLA and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of remediating contamination. Some of our facilities have areas with known soil and/or groundwater contamination. We could be required to spend significant sums to remediate contamination, regardless of whether we caused such contamination, (a) if there are releases or discoveries of hazardous substances at our generating facilities, at disposal sites we currently use or have used, or at other locations for which we may be liable, or (b) if parties contractually responsible to us for contamination fail to or are unable to respond when claims or obligations regarding such contamination arise.

Under current and forecasted market conditions, capital expenditures required by our permit for the Shawville facility are not economic.

Our NPDES permit requires installation of cooling towers or reduction in plant operation by July 2015 at our leased Shawville facility. Accordingly, we plan to place the coal-fired units at the Shawville facility, which is leased, in a long-term protective layup in April 2015. Under the lease agreement for Shawville, our obligations generally are to pay the required rent and to maintain the leased assets in accordance with the lease documentation, including in compliance with prudent competitive electric generating industry practice and applicable laws. We will continue to evaluate our options under the lease, including termination of the lease for economic obsolescence and/or keeping the facility in long-term protective layup during the term of the lease. We do not think that the lease documentation mandates that we operate the facility continuously and, so long as we are not operating it, we do not think that the installation of cooling towers, emissions controls and other expenditures would be required under the lease documentation. During the long-term protective layup of the Shawville facility,

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we would continue to pay the required rent and to maintain the facility as required by the lease. In the event of an early termination, we would seek a termination for obsolescence under the lease agreement and could be required to make a termination payment equal to the difference between the termination value and the proceeds received in connection with the sale of the facility to a third-party, together with such other amounts, if any, required under the lease. At December 31, 2011, the total notional minimum lease payments for the remaining terms of the lease aggregated $203 million and the aggregate termination value for the lease was $218 million. We could have impairment charges related to our Shawville facility leasehold improvements. At December 31, 2011, we have leasehold improvements relating to this facility of $28 million recorded in property, plant and equipment in our consolidated balance sheet.

Our coal-fired generating units produce certain byproducts that involve extensive handling and disposal costs and are subject to government regulation. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the costs of handling and disposing of these byproducts.

As a result of the coal combustion process, we produce significant quantities of ash at our coal-fired generating units that must be disposed of at sites permitted to handle ash. One of our landfills in Maryland has reached design capacity and we expect that another one of our sites in Maryland may reach full capacity in the next few years. As a result, we are developing new ash management facilities and have constructed a facility to prepare ash from certain of our Maryland facilities for beneficial uses. However, the costs associated with developing new ash management facilities could be material, and the amount of time to complete such developments could extend beyond the time when new facilities are needed. Likewise, the new facility for preparing ash for beneficial uses may not operate as expected; or the ash may not be marketed and sold as expected. Additionally, costs associated with third-party ash handling and disposal are material and could have an adverse effect on our financial performance and condition.

We also produce gypsum as a byproduct of the SO_2 scrubbing process at our coal-fired generating facilities, much of which is sold to third parties for use in drywall production. Should our ability to sell such gypsum to third parties be restricted as a result of the lack of demand or otherwise, our gypsum disposal costs could rise materially.

The EPA has proposed two alternatives for regulating byproducts such as ash and gypsum. One of these alternatives would regulate these byproducts as "special wastes" in a manner similar to the regulation of hazardous wastes. If these byproducts are regulated as special wastes, the cost of disposing of these byproducts would increase materially and may limit our ability to recycle them for beneficial use.

Our business is subject to complex government regulations. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the prices at which we are able to sell the electricity we produce, the costs of operating our generating facilities or our ability to operate our facilities.

The majority of our generation is sold at market prices under market-based rate authority granted by the FERC. If certain conditions are not met, the FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of our market-based rate authority could have a materially negative impact on our generating business.

Even when market-based rate authority has been granted, the FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, when it determines that potential market power might exist and that the public interest requires such potential market power to be mitigated. In addition to direct regulation by the FERC, most of our facilities are subject to rules

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and terms of participation imposed and administered by various ISOs and RTOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, ISOs and RTOs may impose bidding and scheduling rules, both to curb the potential exercise of market power and to ensure market functions. Such actions may materially affect our ability to sell and the price we receive for our energy, capacity and ancillary services.

To conduct our business, we must obtain and periodically renew licenses, permits and approvals for our facilities. These licenses, permits and approvals can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain and comply with all necessary licenses, permits and approvals for these facilities.

Conflicts may occur between reliability needs and environmental rules, particularly with increasingly stringent environmental restrictions. Without a consent decree or adjustments to permit requirements, which require long lead times to obtain, we remain subject to environmental penalties or liabilities that may occur as a result of operating in compliance with reliability requirements. Further, we could be subject to citizen suits in these types of circumstances, even if we have received a consent decree or permit adjustment exempting us from environmental requirements.

We cannot predict whether the federal or state legislatures will adopt legislation relating to the restructuring of the energy industry. There are proposals in many jurisdictions that would either roll back or advance the movement toward competitive markets for the supply of electricity, at both the wholesale and retail levels. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could affect our ability to compete successfully, and our business and results of operations could be adversely affected. Similarly, any regulations or laws that favor new generation over existing generation could adversely affect our business.

Risks Related to Level of Indebtedness

Our substantial indebtedness and operating lease obligations could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from meeting or refinancing our obligations.

We have a substantial amount of indebtedness. At December 31, 2011, our consolidated indebtedness was $4.1 billion. In addition, the present values of lease payments under the respective GenOn Mid-Atlantic and REMA operating leases were approximately $881 million and $466 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination value of the respective GenOn Mid-Atlantic and REMA operating leases was $1.3 billion and $735 million, respectively.

Our substantial indebtedness and operating lease obligations could have important consequences for our liquidity, results of operations, financial position and prospects, including our ability to grow in accordance with our strategy. These consequences include the following:

- they may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes;

- a substantial portion of our cash flows from operations must be dedicated to the payment of rent and principal and interest on our indebtedness and will not be available for other purposes, including for working capital, capital expenditures, acquisitions and other general corporate purposes;

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- the debt service requirements of our indebtedness and our lease obligations could make it difficult for us to satisfy or refinance our financial obligations;
- certain of our borrowings, including borrowings under our senior secured credit facility, are at variable rates of interest, exposing us to the risk of increased interest rates;
- they may limit our flexibility in planning for and reacting to changes in our industry;
- they may place us at a competitive disadvantage compared to other, less leveraged competitors;
- our new credit facilities contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interest; and
- we may be more vulnerable in a downturn in general economic conditions or in our business and we may be unable to carry out capital expenditures that are important to our long-term growth or necessary to comply with environmental regulations.

GenOn and its subsidiaries that are holding companies, including GenOn Americas Generation, may not have access to sufficient cash to meet their obligations if their subsidiaries, in particular GenOn Mid-Atlantic, are unable to make distributions.

We and certain of our subsidiaries, including GenOn Americas Generation and GenOn Americas, are holding companies and, as a result, are dependent upon dividends, distributions and other payments from our operating subsidiaries to generate the funds necessary to meet our obligations. In particular, a substantial portion of the cash from our operations is generated by GenOn Mid-Atlantic. The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At December 31, 2011, GenOn Mid-Atlantic satisfied the restricted payments test. At December 31, 2011, REMA did not satisfy the restricted payments test.

We may be unable to generate sufficient cash to service our debt and leases and to post required amounts of cash collateral necessary to hedge economically market risk.

Our ability to pay principal and interest on our debt and the rent on our leases depends on our future operating performance. If our cash flows and capital resources are insufficient to allow us to make scheduled payments on our debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital, restructure or refinance. There can be no assurance that the terms of our debt or leases will allow these alternative measures, that the financial markets will be available to us on acceptable terms or that such measures would satisfy our scheduled debt service and lease rent obligations. If we do not comply with the payment and other material covenants under our debt and lease agreements, we could default under our debt or leases and, in the case of our revolving credit facilities, the commitment to lend us money could terminate.

Our asset management activities may require us to post collateral either in the form of cash or letters of credit. At December 31, 2011, we had approximately $224 million of posted cash collateral and $265 million of letters of credit outstanding under our revolving credit facility primarily to support our asset management activities, trading activities, rent reserve requirements and other commercial arrangements. See note 10 to our consolidated financial statements for further information on our posted cash collateral and letters of credit. Although we seek to structure transactions in a way that reduces our potential liquidity needs for collateral, we may be unable to execute our hedging strategy successfully if we are unable to post the amount of collateral required to enter into and support hedging contracts.

We are an active participant in energy exchange and clearing markets, which require a per-contract initial margin to be posted. The initial margins are determined by the exchanges through the use of proprietary models that rely on a variety of inputs and factors, including market conditions. We have limited notice of any changes to the margin rates. Consequently, we are exposed to changes in the per unit margin rates required by the exchanges and could be required to post additional collateral on short notice.

The terms of our credit facilities and leases restrict our current and future operations, particularly our ability to respond to changes or take certain actions.

Our credit facilities and leases contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including restrictions on our ability to:

- incur additional indebtedness;
- pay dividends or make other distributions or repurchase or redeem capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- sell assets;
- incur liens;
- enter into transactions with affiliates;
- enter into sale-leaseback transactions; and
- consolidate, merge or sell all or substantially all of our assets.

In addition, the restrictive covenants in our credit facilities require us to maintain a ratio of consolidated secured debt (net of up to $500 million in cash and certain collateral assets and deposits) to EBITDA of not more than 3.50 to 1.00, which will be tested at the end of each fiscal quarter and, in the case of EBITDA, will be calculated on a rolling four fiscal quarter basis ending on the last day of such fiscal quarter. Our ability to meet that financial ratio can be affected by events beyond our control. Our failure to comply with the covenants in our credit facilities could result in an event of default under our credit facilities and any other debt to which a cross-default or cross-acceleration provision applies.

Item 1B. *Unresolved Staff Comments*.

None.

Item 2. *Properties.*

Our generating facilities are described under "Business Business Segments" in Item 1 of this Form 10-K. We own or lease oil and gas pipelines that serve our generating facilities. Our principal executive offices at 1000 Main Street, Houston, Texas 77002 are leased through 2018, subject to two five-year renewal options. We also lease other offices, including a trading floor, at 1155 Perimeter Center West, Atlanta, GA 30338. We think that our properties are adequate for our present needs. Except for the Conemaugh, Keystone and Sabine facilities, our interest at December 31, 2011 is 100%

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for each property. We have satisfactory title, rights and possession to our owned facilities, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3. *Legal Proceedings.*

See note 16 to our consolidated financial statements and "Business Regulatory Environment Environmental Regulation Cross-State Air Pollution Rule" in Item 1 for discussion of the material legal proceedings to which we are a party.

Item 4. *Mine Safety Disclosures.*

Not applicable.

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PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*.

The common stock data included in this Item 5 refers to GenOn's common stock from December 3, 2010 and to RRI Energy, Inc.'s common stock (ticker symbol "RRI") through December 2, 2010.

Common Stock. Our common stock trades on the NYSE under the ticker symbol "GEN." On February 17, 2012, we had 85,320 stockholders of record. The closing price of our common stock on December 31, 2011 was $2.61. We have never paid dividends. Some of our debt agreements restrict the payment of dividends. See note 6 to our consolidated financial statements.

We are authorized to issue 2 billion shares of common stock having a par value of $.001 per share and 125 million shares of preferred stock having a par value of $.001 per share. In addition, we reserved shares for unresolved claims related to the Mirant bankruptcy, of which approximately 1.3 million shares had not yet been distributed at December 31, 2011.

The following table sets forth the high and low prices for our common stock as reported by the NYSE for the periods indicated.

	Market Price	
	High	**Low**
2011:		
First Quarter	$ 4.35	$ 3.62
Second Quarter	$ 4.10	$ 3.51
Third Quarter	$ 4.14	$ 2.60
Fourth Quarter	$ 3.18	$ 2.30
2010:		
First Quarter	$ 6.21	$ 3.57
Second Quarter	$ 4.91	$ 3.50
Third Quarter	$ 4.30	$ 3.35
Fourth Quarter	$ 4.04	$ 3.46

Securities Authorized for Issuance under Equity Compensation Plans. See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," for information related to securities authorized for issuance under equity compensation plans.

Stock Performance Graph. The performance graph below is being provided as furnished and not filed, as permitted by 17 Code of Federal Regulations 229.201(e), in this Form 10-K and compares the cumulative total stockholder return on our common stock (GenOn or RRI Energy) with the Standard & Poor's 500 Index and a group of our peer companies in our industry comprised of Allegheny Energy, Inc., Calpine Corporation, Constellation Energy Group, Inc., Dynegy Inc., Mirant, NRG Energy, Inc. and PPL Corporation. The graph assumes that $100 was invested on December 31, 2006, in our common stock (GenOn or RRI Energy) and each of the above indices (except that Calpine Corporation is only included in the peer group since its emergence from bankruptcy in January 2008, Mirant is only included through the Merger close on December 3, 2010 and Allegheny Energy, Inc. is only included through February 24, 2011 because it merged with another company) and that all dividends were reinvested.

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GenOn Energy, Inc.

Total Return Performance

	Indexed Returns					
Company Name/Index	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
GenOn	100.00	184.66	40.68	40.25	26.81	18.37
S&P 500	100.00	105.49	66.46	84.05	96.71	98.76
Peer Group[1]	100.00	141.34	65.30	70.64	64.98	76.50

(1) The Peer Group consists of Allegheny Energy, Inc. (AYE), Calpine Corporation (CPN), Constellation Energy Group, Inc. (CEG), Dynegy Inc. (DYN), Mirant (MIR), NRG Energy, Inc. (NRG) and PPL Corporation (PPL).

Source : SNL Financial LC, Charlottesville, VA

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Item 6. *Selected Financial Data.*

The following discussion should be read in conjunction with our consolidated financial statements and the notes thereto, which are in this Form 10-K. The following tables present our selected consolidated financial information, which is derived from our consolidated financial statements.

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the consolidated financial statements and results below of GenOn include the results of Mirant, from January 1, 2007 through December 2, 2010, and include the results of the combined entities for the period from December 3, 2010 through December 31, 2011. The EPS data has been retroactively adjusted to give effect to the Exchange Ratio. The consolidated financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the consolidated financial statements and other financial information of Mirant.

	2011	2010	2009	2008	2007
			(in millions, except per share data)		
Statements of Operations Data:					
Operating revenues	$ 3,614	$ 2,270	$ 2,309	$ 3,188	$ 2,019
Income (loss) from continuing operations	(189)	(233)	493	1,214	432
Net income (loss)	(189)	(233)	493	1,264	1,994
Basic EPS per common share from continuing operations	$ (0.24)	$ (0.53)	$ 1.20	$ 2.30	$ 0.60
Diluted EPS per common share from continuing operations	$ (0.24)	$ (0.53)	$ 1.20	$ 2.15	$ 0.55

Our statement of operations data for each year reflects the volatility caused by unrealized gains and losses related to derivative financial instruments used to hedge economically electricity and fuel. Changes in the fair value and settlements of derivative financial instruments used to hedge economically electricity are reflected in operating revenue and changes in the fair value and settlements of derivative financial instruments used to hedge economically fuel are reflected in cost of fuel, electricity and other products in the consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the consolidated statements of operations. See note 4 to our consolidated financial statements.

	2011	2010	2009	2008	2007
			(in millions)		
Unrealized gains (losses) included in operating revenues	$ 227	$ 45	$ (2)	$ 840	$ (564)
Unrealized (gains) losses included in cost of fuel, electricity and other products	3	87	(49)	54	(28)
Total	$ 224	$ (42)	$ 47	$ 786	$ (536)

During 2011, we identified an under accrual of post-employment benefits relating to over ten years up to and through 2010. We corrected for the misstatements back to 2006 by adjusting operations and maintenance expense and accumulated deficit, as applicable. See note 8 to our consolidated financial statements.

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For 2011, net loss reflects the following before taxes:

$133 million of impairment losses for the write-off of excess NO_x and SO_2 emissions as a result of the CSAPR. See note 5 to our consolidated financial statements;

$72 million of Merger-related costs consisting of $45 million of charges associated with employee severance, $5 million of charges related to corporate facilities lease impairment and $22 million of charges related to integration and other activities. See note 3 to our consolidated financial statements;

$59 million of large scale remediation and related settlement costs;

$23 million of loss on early extinguishment of debt primarily related to a $16 million premium and a $7 million write-off of unamortized debt issuance costs related to the GenOn North America senior notes that were repaid in 2011. See note 6 to our consolidated financial statements.

For 2010, net loss reflects the following before taxes:

$565 million of impairment losses related to our Dickerson and Potomac River generating facilities. See note 5 to our consolidated financial statements;

$335 million gain on bargain purchase, as retroactively amended, $114 million of Merger-related costs and $24 million related to the accelerated vesting of Mirant's stock-based compensation as a result of the Merger. See notes 2 and 3 to our consolidated financial statements; and

$9 million in write-off of unamortized debt issuance costs. See note 1 to our consolidated financial statements.

For 2009, net income reflects the following before taxes:

$221 million of impairment losses related to our Potomac River generating facility and intangible assets related to our Potrero and Contra Costa generating facilities. See note 5 to our consolidated financial statements.

For 2007, net income reflects the following before taxes:

$175 million impairment loss related to our Lovett generating facility;

$379 million gain related to the settlement of litigation with Pepco; and

$2.0 billion gain on sale of our Philippine business, $63 million gain on sale of our Caribbean business and $38 million gain on sale of certain U.S. generating facilities, all recorded in discontinued operations.

	December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
			(in millions)		
Balance Sheet Data:					
Total assets	$ 12,269	$ 15,199	$ 9,528	$ 10,688	$ 10,538

Current portion of long-term debt	10	2,061	75	46	142
Long-term debt, net of current portion	4,122	4,020	2,556	2,630	2,953
Stockholders' equity	5,117	5,434	4,302	3,750	5,299

The amounts for 2011 and 2010 reflect the assets acquired and the debt transactions entered into related to the Merger. For additional information on the Merger and related debt transactions, see notes 2 and 6 to our consolidated financial statements.

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On January 1, 2010, we adopted revised accounting guidance related to accounting for variable interest entities. As a result, MC Asset Recovery, LLC was deconsolidated from our financial results. The total assets at December 31, 2009 in the table above have been adjusted from amounts previously presented to reflect a $39 million reduction as a result of the deconsolidation of MC Asset Recovery, LLC. The adoption of this accounting guidance did not affect any of the other periods presented. See note 13 to our consolidated financial statements.

Total assets for all periods reflect our election in 2008 to discontinue the net presentation of assets subject to master netting agreements upon adoption of the accounting guidance for offsetting amounts related to certain contracts.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

This section is intended to provide the reader with information that will assist in understanding our financial statements, the changes in those financial statements from year to year and the primary factors contributing to those changes. The following discussion should be read in conjunction with our consolidated financial statements and the notes accompanying those financial statements.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed their Merger. Mirant merged with a wholly-owned subsidiary of RRI Energy, with Mirant surviving the Merger as a wholly-owned subsidiary of RRI Energy. In connection with the all-stock, tax-free Merger, RRI Energy changed its name to GenOn Energy, Inc., Mirant stockholders received a fixed ratio of 2.835 shares of GenOn common stock for each share of Mirant common stock, and Mirant changed its name to GenOn Energy Holdings.

Although RRI Energy was the legal acquirer, the Merger was accounted for as a reverse acquisition, and Mirant was deemed to have acquired RRI Energy for accounting purposes. As a consequence of the reverse acquisition accounting treatment, the historical financial statements presented for periods prior to the Merger date are the historical statements of Mirant, except for stockholders' equity which has been retroactively adjusted for the equivalent number of shares of the legal acquirer. The operations of the former RRI Energy businesses have been included in the financial statements from the date of the Merger. For a discussion of our strategy, see Item 1, "Business Strategy" in this Form 10-K.

We have achieved $160 million in annual cost savings through reductions in corporate overhead and support costs. These cost savings resulted from consolidations in several areas, including headquarters, IT systems and corporate functions such as accounting, human resources and finance. We have estimated the total Merger-related costs at approximately $225 million. These costs include $85 million of advisory and legal fees and $140 million of other Merger-related costs, including costs to achieve the savings. These amounts include $25 million incurred by RRI Energy prior to the Merger. During 2011 and 2010, we incurred $72 million and $114 million, respectively. We expect to incur approximately $8 million and $6 million during 2012 and 2013 and beyond, respectively. See note 3 to our consolidated financial statements.

Our Business

We are a wholesale generator with approximately 23,700 MW of net electric generating capacity located, in many cases, near major metropolitan load centers in the PJM, MISO, Northeast and Southeast regions, and California. We also operate integrated asset management and proprietary trading operations. Our customers are principally ISOs, RTOs and investor-owned utilities.

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See above in Item 1, "Business," for a discussion of our expectations to deactivate some generating facilities, primarily coal-fired facilities, of approximately 3,140 MWs, between 2012 and 2015, as well as our other fleet reductions. Also see "Environmental Matters" below. In connection with these deactivations, we expect to incur some charges beginning in the first quarter of 2012. We are currently determining the appropriate amounts for these charges, which include write-offs for excess materials and supplies inventory, severance and other plant closure costs.

Our commercial operations consist primarily of dispatching electricity, hedging the price of electricity we expect to generate, selling capacity, procuring and managing fuel and providing logistical support for the operation of our facilities (for example, by procuring transportation for coal and natural gas), as well as our proprietary trading operations.

We typically sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (spot price). We use dispatch models to assist in making daily bidding decisions regarding the quantity and price of the power we offer to generate from our facilities and sell into the markets. We bid the energy from our generating facilities into the hour-ahead or day-ahead energy market and sell ancillary services through the ISO and RTO markets. We work with the ISOs and RTOs in real time to ensure that our generating facilities are dispatched economically to meet the reliability needs of the market.

Spot prices for electricity are volatile, as are prices for fuel and emissions allowances. In order to reduce the risk of price volatility and achieve more predictable financial results, we have historically entered into economic hedges forward sales of electricity and forward purchases of fuel and emissions allowances to permit us to produce and sell the electricity to manage the risks associated with such volatility. In addition, given the high correlation between natural gas prices and electricity prices in many of the markets in which we operate, we have entered into forward sales of natural gas to hedge economically our exposure to changes in the price of electricity. We procure our hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options. Our hedges cover various periods, including several years.

We sell capacity either bilaterally or through periodic auctions in each ISO and RTO market in which we participate. These capacity sales provide an important source of predictable revenues for us over the contracted period. At January 24, 2012, total projected contracted capacity and PPA revenues for which prices have been set for 2012 through 2015 are $3.0 billion. Failure to meet our capacity commitments may result in a reduction to our capacity payments through penalties or charges.

In addition to the activities described above, we buy and sell some electricity, fuel and emissions allowances, sometimes through financial derivatives, as part of our proprietary trading, fuel oil management and natural gas transportation and storage activities. We engage in proprietary trading to gain information about the markets in which we operate to support our asset management and to take advantage of selected opportunities that we identify. We enter into fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. We engage in natural gas transportation and storage activities to optimize our physical natural gas and storage positions and manage the physical gas requirements for a portion of our assets. Proprietary trading, fuel oil management and natural gas transportation and storage activities together will typically comprise less than 5% of our realized gross margin. All of our commercial activities are governed by a comprehensive risk management policy, which includes limits on the size of volumetric positions and VaR for our proprietary trading and fuel oil management activities.

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Hedging Activities

We hedge economically a substantial portion of our PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. We hedge economically using products which we expect to be effective to mitigate the price risk of our generation. However, as a result of market liquidity limitations, our hedges often are not an exact match for the generation being hedged, and we have some risks resulting from price differentials for different delivery points. In addition, we have risks for implied differences in heat rates when we hedge economically power using natural gas. Currently, a significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. At January 24, 2012, our aggregate hedge levels based on expected generation for each year were as follows:

	2012[(1)]	2013	2014	2015	2016
Power	78%	54%	21%	15%	14%
Fuel	78%	42%	14%	10%	10%

(1) Percentages represent the period from February through December 2012.

See Item 1A, "Risk Factors Risks Related to Economic and Financial Market Conditions" for a discussion of:

- the risks of consolidation of financial institutions and more restrictive capital constraints and regulation, which could have a negative effect on our ability to hedge economically with creditworthy counterparties; and

- the risks of implementation of the Dodd-Frank Act on our ability to hedge economically our generation, including potentially reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

Capital Expenditures and Capital Resources

For 2011, we invested $436 million for capital expenditures, excluding capitalized interest paid. Capital expenditures for 2011 primarily relate to the construction of the Marsh Landing generating facility, maintenance capital expenditures, the construction of an ash beneficiation facility and include the $68 million payment to Stone & Webster for substantial completion of the Maryland scrubber projects. At December 31, 2011, we have invested $1.591 billion of the $1.674 billion that was budgeted for capital expenditures related to compliance with the Maryland Healthy Air Act. Provisions in the construction contracts for the scrubbers at our Maryland coal-fired units provide for certain payments to be made after final completion of the projects. Assuming we are successful in pursuing our claims in the New York proceeding, the total estimated capital expenditures for compliance with the Maryland Healthy Air Act would not exceed the $1.674 billion we currently have recorded. However, if the costs were to equal the amount claimed by Stone &Webster in the litigation, the total capital expenditures would exceed $1.674 billion by approximately 5%. See note 16 to our consolidated financial statements for further discussion involving the scrubber contract litigation.

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The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for 2012 and 2013:

	2012	2013
	(in millions)	
Maryland Healthy Air Act	$ 83	$
Other environmental	64	120
Maintenance	116	128
Marsh Landing generating facility	342	69
Other construction	13	
Other	19	10
Total	$ 637	$ 327

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures. We plan to fund a substantial portion of the total capital expenditures for the Marsh Landing generating facility pursuant to the GenOn Marsh Landing project financing facility entered into in October 2010. Other environmental capital expenditures set forth above could significantly increase subject to the content and timing of final rules and future market conditions.

Environmental Matters

We decide to invest capital for environmental controls based on relatively certain regulations, an evaluation of various options for regulatory compliance, including different technologies and fuel modification, and the expected economic returns on the capital. As discussed above in "Business Segments," we recently analyzed the investment in environmental controls required for a number of our facilities, primarily coal-fired facilities, and concluded that the forecasted returns on investments necessary to comply with environmental regulations are insufficient. Accordingly, we expect to deactivate the following facilities: Glen Gardner, Niles, Elrama (mothball then retire), New Castle, Titus, Portland and Shawville (long-term protective layup). Likewise, we expect other industry participants to retire coal-fired generating facilities because of the costs associated with more stringent environmental air and water quality requirements, some of which have already been announced. These seven generating facilities along with our Avon Lake facility contributed 13% to our realized gross margin during 2011.

We expect industry retirements of coal-fired generating facilities to contribute to a tightening of supply and demand fundamentals and higher prices for the remaining generating facilities. Consequently, we expect the resulting higher market prices to provide adequate returns on some investment in environmental controls necessary to meet promulgated and anticipated requirements. Accordingly, we expect to invest approximately $586 million to $726 million over the next ten years for SCRs and other major environmental controls to meet certain air and water quality requirements,

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which we expect to fund from existing sources of liquidity. The following table summarizes our expected investment in major environmental controls over the next ten years:

Facility	Control Technology	Expected Timing	Expected Investment Over Ten Years
Kendall	Backpressure steam turbine and air-cooled condenser	2012 - 2014	\$32 - \$35 million
Gilbert Sayreville Werner	SCR	2012 - 2015	\$129 - \$151 million
Conemaugh	Scrubber upgrade and SCR	2012 - 2015	\$93 - \$102 million(1)
Mandalay Ormond Beach	Variable speed pumps	2018 - 2019	\$17 - \$20 million
Chalk Point(2) Dickerson	SCR	2018 - 2021	\$315 - \$418 million

(1) Based on our leased interest in the Conemaugh facility.

(2) For Chalk Point unit 2.

If market power prices rise even higher than our current expectations, we might invest more than \$726 million for major environmental controls if they provide adequate expected returns on investment. In particular, we are continuing to evaluate the viability of environmental controls for our Avon Lake facility (732 MW). Our initial analysis indicates that forecasted returns on such investments are insufficient and we anticipate retiring the coal-fired units at the Avon Lake facility in 2015. The decision with respect to Avon Lake is influenced in part by retirement decisions announced by other companies that we are continuing to evaluate. The decision to invest in environmental controls for Avon Lake requires us to look not only at the cost of the scrubber to comply with MATS but also the costs to comply with expected future regulations, including more stringent $PM_{2.5}$ and ozone NAAQS, and water regulations. An investment in a scrubber, an SCR and water intake screens would be approximately \$500 million during the period between 2013 and 2020.

Given the uncertainty related to these environmental matters and those discussed or referred to in this Form 10-K, we cannot predict their actual outcome or ultimate effect on our business, and such matters could result in a material adverse effect on our results of operations, financial position and cash flows. See "Business Regulatory Environment Environmental Regulation" and "Risk Factors Risks Related to Governmental Regulation and Laws" in Items 1 and 1A, respectively, of this Form 10-K and note 16 to our consolidated financial statements for further discussion.

Commodity Prices

The prices for power and natural gas are low compared to several years ago. The energy gross margin from our baseload coal units is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally unaffected by subsequent changes in commodity prices because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue to add economic hedges to manage the risks associated with volatility in prices and to achieve more predictable realized gross margin. However, we expect realized gross margin will be lower in 2012 compared with 2011.

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Results of Operations

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, our consolidated financial statements and results below of GenOn include the results of the combined entities for the periods from December 3, 2010, and include the results of Mirant through December 2, 2010. The consolidated financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the consolidated financial statements and other financial information of Mirant.

Non-GAAP Performance Measures. The following discussion includes the non-GAAP financial measures realized gross margin and unrealized gross margin to reflect how we manage our business. In our discussion of the results of our reportable segments, we include the components of realized gross margin, which are energy, contracted and capacity, and realized value of hedges. Management generally evaluates our operating results excluding the impact of unrealized gains and losses. When viewed with our GAAP financial results, these non-GAAP financial measures may provide a more complete understanding of factors and trends affecting our business. Realized gross margin represents our gross margin (excluding depreciation and amortization) less unrealized gains and losses on derivative financial instruments. Conversely, unrealized gross margin represents our unrealized gains and losses on derivative financial instruments. None of our derivative financial instruments recorded at fair value is designated as a hedge (other than our interest rate swaps) and changes in their fair values are recognized currently in income as unrealized gains or losses. As a result, our financial results are, at times, volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. Realized gross margin, together with its components energy, contracted and capacity, and realized value of hedges, provide a measure of performance that eliminates the volatility reflected in unrealized gross margin, which is created by significant shifts in market values between periods.

We also disclose the non-GAAP financial measures adjusted income/loss from continuing operations and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. These are also provided on a pro forma basis for 2010. As indicated above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted income/loss from continuing operations and adjusted EBITDA also exclude, as applicable: (a) Merger-related costs, (b) net lower of cost or market adjustments to our commodity inventories, (c) impairment losses, (d) gain/loss on early extinguishment of debt, (e) Western states litigation and similar settlements, (f) large scale remediation and settlement costs, (g) major litigation costs, net of recoveries, (h) postretirement benefits curtailment gain, (i) reversal of the Montgomery County carbon levy assessment for the prior year, and (j) certain other items. We adjust for the subsequent benefit created by commodity inventory utilized in operations that were subject to prior period lower of cost or market adjustments. We exclude or adjust for these items to provide a more meaningful representation of our ongoing results of operations.

We use these non-GAAP financial measures in communications with investors, analysts, rating agencies, banks and other parties. Adjusted EBITDA is a key performance metric in our employee incentive compensation structure for annual bonuses. We think these non-GAAP financial measures provide meaningful representations of our consolidated operating performance and are useful to us and others in facilitating the analysis of our results of operations from one period to another. We view adjusted EBITDA as providing a measure of operating results unaffected by differences in capital structures, capital investment cycles and ages of assets among otherwise comparable companies. We

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encourage our investors to review our financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

The foregoing non-GAAP financial measures may not be comparable to similarly titled non-GAAP financial measures used by other companies.

2011 Compared to 2010

Consolidated Financial Performance

We reported net losses of $189 million and $233 million for 2011 and 2010, respectively. The change in net loss is detailed as follows:

	2011	2010	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 1,780	$ 1,349	$ 431
Unrealized gross margin	224	(42)	266
Total gross margin (excluding depreciation and amortization)	2,004	1,307	697
Operating expenses:			
Operations and maintenance	1,293	846	447
Depreciation and amortization	375	224	151
Impairment losses	133	565	(432)
Gain on sales of assets, net	(6)	(4)	(2)
Total operating expenses, net	1,795	1,631	164
Operating income (loss)	209	(324)	533
Other income (expense), net:			
Gain on bargain purchase, as retroactively amended		335	335
Interest expense, net	(379)	(253)	126
Other, net	(19)	7	26
Total other income (expense), net	(398)	89	487
Loss before income taxes	(189)	(235)	46
Benefit for income taxes		(2)	2
Net loss	$ (189)	$ (233)	$ 44

Realized Gross Margin. Our realized gross margin increase of $431 million was principally a result of the following:

- an increase of $324 million in contracted and capacity primarily as a result of $283 million from our Western PJM/MISO segment, which was formed as a result of the Merger and a $79 million increase in capacity revenues in our California segment, partially offset by a decrease of $43 million primarily resulting from lower capacity prices in our Eastern PJM segment and the shutdown of the Potrero generating facility in our California segment;

- an increase of $65 million in energy primarily as a result of $248 million from our Western PJM/MISO segment, which was formed as a result of the Merger, partially offset by a decrease in generation volumes in Eastern PJM primarily as a result of contracting dark spreads and spark spreads; and

- an increase of $42 million in realized value of hedges primarily as a result of $58 million from our Western PJM/MISO segment, which was formed as a result of the Merger and an increase

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in coal hedges primarily as a result of prices, partially offset by a decrease in power hedges as a result of prices.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $224 million in 2011, which included a $466 million net increase in the value of hedge and proprietary trading contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by $242 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized losses of $42 million in 2010, which included $389 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $347 million net increase in the value of hedge and proprietary trading contracts for future periods. The increase in value was primarily related to decreases in forward power and natural gas prices offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010.

Operating Expenses. Our operating expenses increase of $164 million was principally a result of the following:

- an increase of $447 million in operations and maintenance expense primarily related to the following:

  - an increase of $569 million related to the addition of the RRI Energy generating facilities and corporate costs as a result of the Merger;

  - a $49 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty);

  - $37 million curtailment gain recognized in 2010 resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees. See note 8 to our consolidated financial statements.; and

  - $15 million recognized in 2011 for major litigation costs, net of recoveries

  - a $10 million accrual for the Brandywine storm damage and remediation, partially offset by

  - a decrease of $42 million in Merger-related costs;

  - a decrease of $38 million related to outages and some labor costs;

  - $32 million recognized in 2010 related to a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as a part of the agreement with the City of Alexandria, Virginia. See note 5 to our consolidated financial statements;

  - $24 million recognized in 2010 for the accelerated vesting of Mirant's stock-based compensation as a result of the Merger; and a decrease of $17 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to a refund received in 2011 of CO_2 levies paid in 2010;

an increase of $151 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger, partially offset by decreases as a result of reductions in the carrying values of the Dickerson and Potomac River generating facilities as a result of impairment losses in 2010, and the shutdown of the Potrero generating facility; and

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- a decrease of $432 million in impairment losses. In 2011, we recognized $133 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR. In 2010, we recognized $565 million in impairment losses related to our Dickerson and Potomac River generating facilities. See note 5 to our consolidated financial statements.

Gain on Bargain Purchase. We reported a gain on bargain purchase of $335 million, as retroactively amended, during 2010. The gain on the bargain purchase is primarily a result of differences between the long-term fundamental value of the generating facilities and the effect of the near-term view of the equity markets on the price of Mirant common stock at the close of the Merger. See note 2 to our consolidated financial statements. The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, we have conducted an assessment of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred.

Interest Expense, Net. Interest expense, net increase of $126 million was primarily a result of the following:

- a $245 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger; partially offset by

- a $123 million decrease related to lower interest expense as a result of (a) repayment of the GenOn North America senior secured credit facilities and senior notes in 2010 and 2011, respectively, and (b) repayment of GenOn Americas Generation senior unsecured notes in 2011.

Other, Net. Other, net change of $26 million was primarily a result of the following:

- $23 million of other expense relating to the loss on early extinguishment of debt primarily related to a $16 million premium and a $7 million write-off of unamortized debt issuance costs related to the GenOn North America senior notes that were repaid in 2011; and

- $14 million of other income, recognized in accordance with accounting guidance, relating to the reimbursement of pre-merger interest paid by RRI Energy on GenOn's debt in accordance with the pre-merger escrow arrangements in 2010; partially offset by

- $9 million of other expense relating to the write-off of unamortized debt issuance costs related to the GenOn North America senior secured term loan that was repaid in 2010.

Adjusted Income/Loss from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income/loss from continuing operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. In order to provide a more meaningful comparison of our results, the following compares actual results for 2011 to pro forma information for 2010 and provides discussion of the changes. The unaudited pro forma information is based on the historical consolidated financial statements of both RRI Energy and Mirant and has been prepared to illustrate the effects of the Merger, assuming the Merger had been consummated on January 1, 2010. The unaudited pro forma information primarily includes the following adjustments, among others:

- amortization of fair value adjustments related to energy-related contracts;

- additional fuel expense related to fair value adjustments of fuel inventories;

- effects of fair value adjustments of property, plant and equipment;

effects of fair value adjustments of debt and the issuance of a new revolving credit facility, new senior secured term loan and new senior unsecured notes; and

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adjustments to income taxes for a zero percent rate applied to the pro forma adjustments and historical federal and state deferred tax expense/benefit.

The unaudited pro forma results exclude:

Merger-related costs because these costs reflect non-recurring charges directly related to the Merger; and

cost savings from operating efficiencies or synergies that we expect to result from the Merger.

The pro forma financial information is not necessarily indicative of the operating results that would have occurred if the Merger had been completed at the date indicated, nor is it indicative of our future operating results.

	2011	Pro Forma 2010	2010
		(in millions)	
Net loss	$ (189)	$ (740)	$ (233)
Unrealized (gains) losses	(224)	(27)	42
Impairment losses	133	926(1)	565
Merger-related costs	72		114
Large scale remediation and settlement costs	59		
Loss on early extinguishment of debt	23		9
Major litigation costs, net of recoveries	15		
Reversal of Montgomery County carbon levy assessment for prior year	(8)		
Lower of cost or market inventory adjustments, net	(3)	(22)	(4)
Potomac River settlement obligation		32	32
Mirant's accelerated vesting of stock-based compensation			24
Reimbursement of pre-merger expenses from RRI Energy			(14)
Kern River settlement		(40)	
Western states litigation and similar settlements		17(1)	
Postretirement benefits curtailment gain		(37)	(37)
Gain on bargain purchase, as retroactively amended			(335)
Other, net	(10)	(6)	
Adjusted income (loss) from continuing operations	(132)	103	163
Interest expense, net	379	427	253
Benefit for income taxes		(2)	(2)
Depreciation and amortization	375	391	224
Adjusted EBITDA	$ 622	$ 919	$ 638

(1) During 2010, RRI Energy recognized (a) impairment losses of $361 million for its Elrama, Niles, Titus and New Castle generating facilities and (b) $17 million to settle the Western states and other litigation.

Adjusted EBITDA was $622 million for 2011 compared to $919 million on a pro forma basis for 2010. The decline primarily was related to a reduction in energy gross margin in Eastern PJM as a result of reduced generation volumes and lower contracted and capacity revenues. The decline was partially offset by lower adjusted operating and other expenses, primarily related to merger cost savings and reduced planned outages and projects.

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The adjusted loss from continuing operations was $132 million for 2011 compared to adjusted income from continuing operations of $103 million on a pro forma basis for 2010. The decline was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense, net and depreciation and amortization expense.

Our net loss was $189 million for 2011 compared to $740 million on a pro forma basis for 2010. The decrease in net loss was primarily a result of a $793 million decrease in impairment losses and an increase in unrealized gross margin, partially offset by Merger-related costs, $59 million recognized in 2011 for large scale remediation and settlement costs and the same items that affected adjusted income/loss from continuing operations.

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. In conjunction with the Merger, we began reporting in five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. Prior to the Merger, we had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. Amounts for 2010 were reclassified to conform to the current segment presentation.

Gross Margin Overview

The following tables detail realized and unrealized gross margin, by operating segments:

	2011					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
	(in millions)					
Energy	$ 167	$ 281	$ 10	$ 58	$ 19	$ 535
Contracted and capacity	298	315	205		92	910
Realized value of hedges	274	58	5		(2)	335
Total realized gross margin	739	654	220	58	109	1,780
Unrealized gross margin	120	81	2	28	(7)	224
Total gross margin[1]	$ 859	$ 735	$ 222	$ 86	$ 102	$ 2,004

	2010					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
	(in millions)					
Energy	$ 384	$ 33	$	$ 34	$ 19	$ 470
Contracted and capacity	341	32	126		87	586
Realized value of hedges	280				13	293
Total realized gross margin	1,005	65	126	34	119	1,349
Unrealized gross margin	7	(22)		(8)	(19)	(42)
Total gross margin[1]	$ 1,012	$ 43	$ 126	$ 26	$ 100	$ 1,307

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales, our proprietary trading and fuel oil management activities, and natural gas transportation and storage activities.

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Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts (which we had at Potrero through February 28, 2011), through PPAs and tolling agreements and from ancillary services.

Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Operating Statistics

Our total margin capture factor was 89% during 2011.

The following table summarizes power generation volumes by segment:

	2011	2010	Increase/ (Decrease)	Increase/ (Decrease)[2]
		(in gigawatt hours)		
Eastern PJM:				
Baseload	11,462	14,271	(2,809)	(20)%
Intermediate	727	1,120	(393)	(35)%
Peaking	115	219	(104)	(47)%
Total Eastern PJM	12,304	15,610	(3,306)	(21)%
Western PJM/MISO:				
Baseload	20,121	2,119	18,002	NM
Intermediate[1]		(1)	1	NM
Peaking	82	2	80	NM
Total Western PJM/MISO	20,203	2,120	18,083	NM
California:				
Intermediate	382	530	(148)	(28)%
Peaking[1]	3	(1)	4	NM
Total California	385	529	(144)	(27)%
Other Operations:				
Baseload	1,534	1,485	49	3%
Intermediate	237	395	(158)	(40)%
Peaking	334	22	312	NM
Total Other Operations	2,105	1,902	203	11%
Total	34,997	20,161	14,836	74%

(1) Negative amounts denote net energy used by the generating facility.

(2) NM means not meaningful.

The total increase in power generation volumes for 2011, as compared to 2010, was primarily the result of the following:

Eastern PJM. The decrease in our baseload and intermediate generation volumes was primarily as a result of contracting dark spreads and spark spreads.

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Western PJM/MISO. The Western PJM/MISO segment was added as a result of the Merger.

California. The decrease in our intermediate generation volumes was primarily the result of the shutdown of the Potrero generating facility, partially offset by the addition of the RRI Energy generating facilities as a result of the Merger.

Other Operations. The increase in our baseload and peaking generation volumes was primarily related to the addition of the RRI Energy generating facilities as a result of the Merger, offset in part by a reduction in our available capacity at the Bowline and Kendall generating facilities.

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,341 MW at December 31, 2011 and 2010.

The following table summarizes the results of operations of our Eastern PJM segment:

	2011	2010	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 167	$ 384	$ (217)
Contracted and capacity	298	341	(43)
Realized value of hedges	274	280	(6)
Total realized gross margin	739	1,005	(266)
Unrealized gross margin	120	7	113
Total gross margin (excluding depreciation and amortization)	859	1,012	(153)
Operating Expenses:			
Operations and maintenance	482	495	(13)
Depreciation and amortization	146	142	4
Impairment losses	95	1,153	(1,058)
Gain on sales of assets, net		(3)	3
Total operating expenses, net	723	1,787	(1,064)
Operating income (loss)	$ 136	$ (775)	$ 911

Gross Margin

The decrease of $266 million in realized gross margin was principally a result of the following:

- a decrease of $217 million in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads and spark spreads;

- a decrease of $43 million in contracted and capacity, primarily as a result of an $85 million decrease from lower capacity prices and an $8 million decrease from ancillary services, offset by $47 million from the addition of the RRI Energy generating facilities as a result of the Merger; and

- a decrease of $6 million in realized value of hedges, primarily as a result of a $37 million decrease in power hedges primarily resulting from prices, offset in part by a $28 million increase in our coal hedges resulting from prices.

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Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $120 million in 2011, which included a $338 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by $218 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $7 million in 2010, which included a $326 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was substantially offset by $319 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The decrease of $1.1 billion in operating expenses was principally a result of the following:

- a decrease of $1.1 billion in impairment losses. In 2011, we recognized $95 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR. In 2010, we recognized $1.2 billion in impairment losses, including $616 million related to the write-off of goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet and $537 million related to our Dickerson and Potomac River generating facilities. The goodwill impairment loss was eliminated upon consolidation at GenOn North America. See note 5 to our consolidated financial statements; and

- a decrease of $13 million in operations and maintenance expense primarily related to the following:

  - $32 million recognized in 2010 related to a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as part of the agreement with the City of Alexandria, Virginia. See note 5 to our consolidated financial statements;

  - a decrease of $21 million resulting from a change in the allocation methodology for overhead costs and a larger number of generating facilities to which the allocated costs are distributed, both as a result of the Merger;

  - a decrease of $20 million as a result of outages and some labor costs;

  - a decrease of $17 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to a refund received in 2011 of CO_2 levies paid in 2010; and

  - a decrease of $6 million resulting from changes in asset retirement obligation assumptions; partially offset by

  - a $49 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty);

  - $15 million recognized in 2011 for major litigation costs, net of recoveries;

an increase of $13 million related to the addition of the RRI Energy generating facilities as a result of the Merger; and

a $10 million accrual for the Brandywine storm damage and remediation, partially offset by

an increase of $4 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger and accelerated depreciation recognized

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in connection with the abandonment of a pipeline, partially offset by decreases as a result of reductions in the carrying values of the Dickerson and Potomac River generating facilities as a result of impairment losses in 2010.

Western PJM/MISO

Our Western PJM/MISO segment was established as a result of the Merger and includes 23 generating facilities (all RRI Energy generating facilities) with total net generating capacity of 7,483 MW at December 31, 2011 and 2010.

The following table summarizes the results of operations of our Western PJM/MISO segment:

	2011	2010(1)	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 281	$ 33	$ 248
Contracted and capacity	315	32	283
Realized value of hedges	58		58
Total realized gross margin	654	65	589
Unrealized gross margin	81	(22)	103
Total gross margin (excluding depreciation and amortization)	735	43	692
Operating Expenses:			
Operations and maintenance	495	45	450
Depreciation and amortization	118	9	109
Impairment losses	4		4
Total operating expenses, net	617	54	563
Operating income (loss)	$ 118	$ (11)	$ 129

(1) Represents the results of operations of our Western PJM/MISO segment from December 3, 2010 through December 31, 2010.

California

Our California segment consists of seven generating facilities with total net generating capacity of 5,391 MW (excluding the Potrero facility of 362 MW, which was shut down on February 28, 2011) at December 31, 2011 and eight generating facilities with total net generating capacity of 5,753 MW at December 31, 2010. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

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The following table summarizes the results of operations of our California segment:

	2011	2010	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 10	$	$ 10
Contracted and capacity	205	126	79
Realized value of hedges	5		5
Total realized gross margin	220	126	94
Unrealized gross margin	2		2
Total gross margin (excluding depreciation and amortization)	222	126	96
Operating Expenses:			
Operations and maintenance	147	78	69
Depreciation and amortization	44	31	13
Impairment losses	14		14
Gain on sales of assets, net	(5)		(5)
Total operating expenses, net	200	109	91
Operating income	$ 22	$ 17	$ 5

Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for the majority of the capacity from these units. Our Potrero units were subject to RMR arrangements through February 28, 2011, the date of the shutdown. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Our gross margin generally is not affected by changes in power generation volumes from facilities under such arrangements.

For those units that are not under tolling agreements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

The increase of $94 million in realized gross margin was principally a result of the following:

- an increase of $79 million in contracted and capacity primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility; and

- an increase of $10 million in energy primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger.

Operating Expenses

The increase of $91 million in operating expenses was principally a result of the following:

- an increase of $69 million in operations and maintenance expense resulting from $83 million related to the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $8 million resulting from the shutdown of the Potrero generating facility;

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- an increase of $13 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger, partially offset by a decrease as a result of the shutdown of the Potrero generating facility; and

- an increase of $14 million in impairment losses for the write-off of excess SO_2 emissions allowances during 2011 as a result of the CSAPR, partially offset by

- an increase of $5 million in gain on sales of assets as a result of the sale of equipment from our Potrero generating facility.

Energy Marketing

Our Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities.

The following table summarizes the results of operations of our Energy Marketing segment:

	2011	2010	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 58	$ 34	$ 24
Contracted and capacity			
Realized value of hedges			
Total realized gross margin	58	34	24
Unrealized gross margin	28	(8)	36
Total gross margin (excluding depreciation and amortization)	86	26	60
Operating Expenses:			
Operations and maintenance	4	9	(5)
Depreciation and amortization	2	1	1
Total operating expenses, net	6	10	(4)
Operating income	$ 80	$ 16	$ 64

Gross Margin

The increase of $24 million in realized gross margin was primarily as a result of an increase in fuel oil management activities, natural gas transportation activities and proprietary trading.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $28 million in 2011, which included a $19 million net increase in the value of contracts for future periods and $9 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and

- unrealized losses of $8 million in 2010, which included $50 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, substantially offset by a $42 million net increase in the value of contracts for future periods.

Other Operations

Our Other Operations segment consisted of nine generating facilities with total net generating capacity of 5,068 MW at December 31, 2011 and 2010. We sold our Indian River generating facility (586 MW), which was included in the Other Operations segment, in January 2012 for $12 million.

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Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

The following table summarizes the results of operations of our Other Operations segment:

	2011	2010	Increase/ (Decrease)
	(in millions)		
Gross Margin:			
Energy	$ 19	$ 19	$
Contracted and capacity	92	87	5
Realized value of hedges	(2)	13	(15)
Total realized gross margin	109	119	(10)
Unrealized gross margin	(7)	(19)	12
Total gross margin (excluding depreciation and amortization)	102	100	2
Operating Expenses:			
Operations and maintenance	165	219	(54)
Depreciation and amortization	65	41	24
Impairment losses	20	28	(8)
Gain on sales of assets, net	(1)	(1)	
Total operating expenses, net	249	287	(38)
Operating loss	$ (147)	$ (187)	$ 40

Gross Margin

The decrease of $10 million in realized gross margin was principally a result of the following:

- a decrease of $15 million in realized value of hedges primarily as a result of a decline in the value realized from our power and oil hedges, partially offset by

- an increase of $5 million in contracted and capacity primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by decreases attributable to our facilities located in the Northeast resulting from lower capacity prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $7 million in 2011, which included $4 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and $3 million net decrease in the value of hedge contracts for future periods; and

- unrealized losses of $19 million in 2010 as a result of the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The decrease of $38 million in operating expenses was principally the result of the following:

a decrease of $54 million in operations and maintenance expense primarily related to the following:

- a decrease of $42 million in Merger-related costs;
- $24 million recognized in 2010 for the accelerated vesting of Mirant's stock-based compensation as a result of the Merger;

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a decrease of $12 million as a result of outages and some labor costs; and

a decrease of $11 million resulting from a change in the allocation methodology for overhead costs and a larger number of generating facilities to which the allocated costs are distributed, both as a result of the Merger; partially offset by

$37 million curtailment gain recognized in 2010 resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees. See note 8 to our consolidated financial statements; and

an increase of $23 million related to the addition of the RRI Energy generating facilities as a result of the Merger; and

a decrease of $8 million in impairment losses. In 2011, we recognized $20 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR. In 2010, we recognized $28 million in impairment losses for capitalized interest recorded at GenOn North America related to the Dickerson and Potomac River generating facilities, partially offset by

an increase of $24 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger.

2010 Compared to 2009

Consolidated Financial Performance

We reported a net loss of $233 million and net income of $493 million for 2010 and 2009, respectively. The change in net income/loss is detailed as follows:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 1,349	$ 1,552	$ (203)
Unrealized gross margin	(42)	47	(89)
Total gross margin (excluding depreciation and amortization)	1,307	1,599	(292)
Operating expenses:			
Operations and maintenance	846	610	236
Depreciation and amortization	224	149	75
Impairment losses	565	221	344
Gain on sales of assets, net	(4)	(22)	18
Total operating expenses, net	1,631	958	673
Operating income (loss)	(324)	641	(965)
Other income (expense), net:			
Gain on bargain purchase, as retroactively amended	335		(335)
Interest expense, net	(253)	(135)	118
Other, net	7	(1)	(8)
Total other income (expense), net	89	(136)	(225)

Income (loss) before income taxes		(235)		505		(740)
Provision (benefit) for income taxes		(2)		12		(14)
Net income (loss)	$	(233)	$	493	$	(726)

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Realized Gross Margin. For 2010, our realized gross margin decrease of $203 million was principally a result of the following:

- a decrease of $336 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $293 million and $629 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, offset in part by the amount by which contract prices for fuel exceeded market prices for fuel; partially offset by

- an increase of $113 million in energy, primarily as a result of an increase in energy in Eastern PJM because of an increase in the average settlement price for power, a decrease in the cost of emissions allowances, higher generation volumes and the addition of the Western PJM/MISO segment in 2010, offset in part by a decrease in realized gross margin from proprietary trading and fuel oil management activities in Energy Marketing and an increase in the average price of fuel; and

- an increase of $20 million in contracted and capacity primarily as a result of the addition of the Western PJM/MISO segment in 2010 as a result of the Merger, an increase in ancillary services revenue and additional megawatts of capacity sold in Eastern PJM, offset in part by a decrease in capacity prices in Eastern PJM.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $42 million in 2010, which included $389 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, substantially offset by a $347 million net increase in the value of hedge and proprietary trading contracts for future periods. The increase in value was primarily related to decreases in forward power and natural gas prices offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010; and

- unrealized gains of $47 million in 2009, which included a $686 million net increase in the value of hedge and trading contracts for future periods primarily related to decreases in forward power and natural gas prices, substantially offset by $639 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses. Our operating expenses increase of $673 million was primarily a result of the following:

- an increase of $344 million in impairment losses. In 2010, we recognized $565 million in impairment losses related to our Dickerson and Potomac River generating facilities. In 2009, we recognized $221 million in impairment losses related to our Potomac River generating facility and intangible assets related to our Potrero and Contra Costa generating facilities. See note 5 to our consolidated financial statements;

- an increase of $236 million in operations and maintenance expense primarily related to the following:

  - an increase of $114 million in Merger-related costs incurred in 2010, which included $67 million of advisory and legal costs and $35 million related to severance;

  - an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, comprised of a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See notes 13 and 16 to our consolidated financial statements;

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- an increase of $45 million related to the addition of the Western PJM/MISO segment as a result of the Merger;
- an increase of $32 million related to the recognition of a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as a part of the agreement with the City of Alexandria, Virginia. See note 5 to our consolidated financial statements;
- an increase of $29 million primarily as a result of an increase in costs related to the operation of the scrubbers at our Maryland generating facilities and the Montgomery County, Maryland CO_2 levy imposed on our Dickerson generating facility beginning in May 2010, offset in part by a decrease in planned maintenance costs in 2010 compared to 2009; and
- an increase of $24 million related to the accelerated vesting of Mirant's stock-based compensation as a result of the Merger; partially offset by
- a decrease of $37 million as a result of a curtailment gain recorded during the second quarter of 2010 resulting from an amendment to our postretirement healthcare benefits plan covering Eastern PJM union employees. See note 8 to our consolidated financial statements;
- a decrease of $20 million primarily related to lower property taxes because of a lower assessed value for the Lovett generating facility which was demolished in 2009 and a decrease in shutdown costs associated with this generating facility; and
- a decrease of $12 million related to severance and stock-based compensation costs not related to the Merger primarily as a result of the departure of certain executives in 2009;

- an increase of $75 million in depreciation and amortization expense primarily as a result of the scrubbers at our Maryland generating facilities that were placed in service in December 2009 and the addition of the long-lived assets acquired in the Merger; and
- a decrease of $18 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Gain on Bargain Purchase. We reported a gain on bargain purchase of $335 million, as retroactively amended, during 2010. The gain on the bargain purchase is primarily a result of differences between the long-term fundamental value of the generating facilities and the effect of the near-term view of the equity markets on the price of Mirant common stock at the close of the Merger. See note 2 to our consolidated financial statements. The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, we have conducted an assessment of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred.

Interest Expense, Net. Interest expense, net increase of $118 million was primarily a result of the following:

- $66 million increase primarily resulting from higher interest expense as a result of lower capitalized interest because of the scrubbers at our Maryland generating facilities that were placed in service in December 2009; and
- $47 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger.

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Other, Net. Other, net change of $8 million was primarily a result of the following:

- $14 million of other income, recognized in accordance with accounting guidance, relating to the reimbursement of pre-merger interest paid by RRI Energy on GenOn's debt in accordance with the pre-merger escrow arrangements; partially offset by

- $9 million of other expense relating to the write-off of unamortized debt issuance costs related to the GenOn North America senior secured term loan that was repaid in 2010.

Provision (Benefit) for Income Taxes. Provision (benefit) for income taxes changed by $14 million, primarily as a result of decreased federal taxable income reducing federal and state alternative minimum taxes.

Adjusted Income from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income from continuing operations and adjusted EBITDA to net income/loss. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below.

	2010	2009
	(in millions)	
Net income (loss)	$ (233)	$ 493
Unrealized (gains) losses	42	(47)
Impairment losses	565	221
Merger-related costs	114	
Potomac River settlement obligation	32	
Mirant's accelerated vesting of stock-based compensation	24	
Loss on early extinguishment of debt	9	
Lower of cost or market inventory adjustments, net	(4)	(31)
Reimbursement of pre-merger expenses from RRI Energy	(14)	
Postretirement benefits curtailment gain	(37)	
Gain on bargain purchase, as retroactively amended	(335)	
Bankruptcy charges and legal contingencies		(62)
Severance and bonus plan for dispositions		13
Lovett shut down costs		5
Other		1
Adjusted income from continuing operations	163	593
Interest expense, net	253	135
Provision (benefit) for income tax	(2)	12
Depreciation and amortization	224	149
Adjusted EBITDA	$ 638	$ 889

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. In conjunction with the Merger, we began reporting in five segments in the fourth quarter of 2010: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. Prior to the Merger, we had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. Amounts for 2010 prior to the Merger and for 2009 were reclassified to conform to the current segment presentation.

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Gross Margin Overview

The following tables detail realized and unrealized gross margin, by operating segments:

	2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
	(in millions)						
Energy	$ 384	$ 33	$	$ 34	$ 19	$	$ 470
Contracted and capacity	341	32	126		87		586
Realized value of hedges	280				13		293
Total realized gross margin	1,005	65	126	34	119		1,349
Unrealized gross margin	7	(22)		(8)	(19)		(42)
Total gross margin(1)	$ 1,012	$ 43	$ 126	$ 26	$ 100	$	$ 1,307

	2009						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
	(in millions)						
Energy	$ 170	$	$	$ 167	$ 23	$ (3)	$ 357
Contracted and capacity	351		122		93		566
Realized value of hedges	586				43		629
Total realized gross margin	1,107		122	167	159	(3)	1,552
Unrealized gross margin	144			(113)	16		47
Total gross margin(1)	$ 1,251	$	$ 122	$ 54	$ 175	$ (3)	$ 1,599

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(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales, our proprietary trading and fuel oil management activities, and natural gas transportation and storage activities.

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts, through PPAs and tolling agreements and from ancillary services.

Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

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Operating Statistics

The following table summarizes power generation volumes by segment:

	2010	2009	Increase/ (Decrease)	Increase/ (Decrease)
		(in gigawatt hours)		
Eastern PJM:				
Baseload	14,271	13,500	771	6%
Intermediate	1,120	363	757	209%
Peaking	219	92	127	138%
Total Eastern PJM	15,610	13,955	1,655	12%
Western PJM/MISO:				
Baseload	2,119		2,119	N/A
Intermediate[(1)]	(1)		(1)	N/A
Peaking	2		2	N/A
Total Western PJM/MISO	2,120		2,120	N/A
California:				
Intermediate	530	1,050	(520)	(50)%
Peaking[(1)]	(1)	4	(5)	(125)%
Total California	529	1,054	(525)	(50)%
Other Operations:				
Baseload	1,485	1,425	60	4%
Intermediate	395	673	(278)	(41)%
Peaking	22	3	19	633%
Total Other Operations	1,902	2,101	(199)	(9)%
Total	20,161	17,110	3,051	18%

(1) Negative amounts denote net energy used by the generating facility.

The total increase in power generation volumes for 2010, as compared to 2009, was primarily the result of the following:

Eastern PJM. An increase in our generation volumes primarily as a result of higher power prices resulting from an increase in demand because of higher average temperatures and a decrease in outages in 2010 compared to 2009.

Western PJM/MISO. The Western PJM/MISO segment was formed as a result of the Merger.

California. The decrease in our intermediate generation volumes is primarily the result of the TransBay Cable becoming operational during the fourth quarter of 2010, which reduced the demand for our natural gas-fired Potrero generating unit.

Other Operations. A decrease in our Other Operations intermediate generation as a result of transmission upgrades in 2009 which reduced the demand for the oil-fired intermediate units at our Canal generating facility and unplanned outages in 2010, partially offset by increases in generation volumes by our baseload and peaking units.

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Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,341 MW at December 31, 2010 and four generating facilities with total net generating capacity of 5,209 MW at December 31, 2009.

The following table summarizes the results of operations of our Eastern PJM segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 384	$ 170	$ 214
Contracted and capacity	341	351	(10)
Realized value of hedges	280	586	(306)
Total realized gross margin	1,005	1,107	(102)
Unrealized gross margin	7	144	(137)
Total gross margin (excluding depreciation and amortization)	1,012	1,251	(239)
Operating Expenses:			
Operations and maintenance	495	434	61
Depreciation and amortization	142	98	44
Impairment losses	1,153	385	768
Gain on sales of assets, net	(3)	(14)	11
Total operating expenses, net	1,787	903	884
Operating income (loss)	$ (775)	$ 348	$ (1,123)

Gross Margin

The decrease of $102 million in realized gross margin was principally a result of the following:

- a decrease of $306 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $280 million and $586 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for coal exceeded market prices for coal; and

- a decrease of $10 million in contracted and capacity primarily related to lower average capacity prices, offset in part by an increase in ancillary services revenue and additional megawatts of capacity sold in 2010; partially offset by

- an increase of $214 million in energy, primarily as a result of an increase in the average settlement price for power, a decrease in the cost of emissions allowances, and higher generation volumes, offset in part by an increase in the average price of fuel.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $7 million in 2010, which included a $326 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was substantially offset by $319 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

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unrealized gains of $144 million in 2009, which included a $633 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by $489 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $884 million was primarily a result of the following:

- an increase of $768 million in impairment losses. In 2010, we recognized $1.2 billion in impairment losses, including $616 million related to the write-off of goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet and $537 million related to our Dickerson and Potomac River generating facilities. In 2009, we recognized $385 million in impairment losses, including $202 million related to our Potomac River generating facility and $183 million related to goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet. The goodwill impairment loss and related goodwill balance are eliminated upon consolidation at GenOn North America. See note 5 to our consolidated financial statements;

- an increase of $44 million in depreciation and amortization expense primarily as a result of the scrubbers at our Maryland generating facilities that were placed in service in December 2009, offset in part by a decrease in the carrying value of the Potomac River generating facility as a result of the impairment charge taken in the fourth quarter of 2009;

- an increase of $32 million related to the recognition of a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as part of the agreement with the City of Alexandria, Virginia. See note 5 to our consolidated financial statements;

- an increase of $29 million in operations and maintenance expense primarily as a result of an increase in costs related to the operation of the scrubbers at our Maryland generating facilities and the Montgomery County, Maryland CO_2 levy imposed on our Dickerson generating facility beginning in May 2010, offset in part by a decrease in planned maintenance costs in 2010 compared to 2009; and

- a decrease of $11 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Western PJM/MISO

Our Western PJM/MISO segment was established as a result of the Merger and includes 23 generating facilities (all RRI Energy generating facilities) with total net generating capacity of 7,483 MW at December 31, 2010.

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The following table summarizes the results of operations of our Western PJM/MISO segment from December 3, 2010 through December 31, 2010:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 33	$	$ 33
Contracted and capacity	32		32
Realized value of hedges			
Total realized gross margin	65		65
Unrealized gross margin	(22)		(22)
Total gross margin (excluding depreciation and amortization)	43		43
Operating Expenses:			
Operations and maintenance	45		45
Depreciation and amortization	9		9
Total operating expenses, net	54		54
Operating loss	$ (11)	$	$ (11)

California

Our California segment consists of eight generating facilities with total net generating capacity of 5,753 MW at December 31, 2010 and three generating facilities with total net generating capacity of 2,347 MW at December 31, 2009. Our California segment also includes business development efforts for new generation in California, including GenOn Marsh Landing.

The following table summarizes the results of operations of our California segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$	$	$
Contracted and capacity	126	122	4
Realized value of hedges			
Total realized gross margin	126	122	4
Unrealized gross margin			
Total gross margin (excluding depreciation and amortization)	126	122	4
Operating Expenses:			
Operations and maintenance	78	79	(1)
Depreciation and amortization	31	22	9
Impairment losses		14	(14)
Gain on sales of assets, net			
Total operating expenses, net	109	115	(6)
Operating income	$ 17	$ 7	$ 10

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Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units, and our Potrero units were subject to RMR arrangements in 2010 and 2009. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Therefore, our gross margin generally is not affected by changes in power generation volumes from these facilities.

For those units that are not under tolling or RMR agreements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

Operating Expenses

The decrease of $6 million in operating expenses was principally a result of the following:

- a decrease of $14 million of impairment losses related to our Potrero and Contra Costa generating facilities during 2009. See note 5 to our consolidated financial statements; partially offset by

- an increase of $9 million in depreciation expense as a result of a decrease in the useful life of our Potrero generating facility because of the settlement with the City and County of San Francisco executed in the third quarter of 2009. See note 5 to our consolidated financial statements.

Energy Marketing

Our Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities.

The following table summarizes the results of operations of our Energy Marketing segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 34	$ 167	$ (133)
Contracted and capacity			
Realized value of hedges			
Total realized gross margin	34	167	(133)
Unrealized gross margin	(8)	(113)	105
Total gross margin (excluding depreciation and amortization)	26	54	(28)
Operating Expenses:			
Operations and maintenance	9	11	(2)
Depreciation and amortization	1	1	
Total operating expenses, net	10	12	(2)
Operating income	$ 16	$ 42	$ (26)

Gross Margin

The decrease of $133 million in realized gross margin was principally a result of a $76 million decrease from proprietary trading activities and a $57 million decrease from our fuel oil management activities. The decrease in the contribution from proprietary trading was primarily a result of a decrease in the realized value associated with power positions in 2010 as compared to 2009. The decrease in the

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contribution from fuel oil management was a result of lower gross margin on positions used to hedge economically the fair value of our physical fuel oil inventory.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $8 million in 2010, which included $50 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, substantially offset by a $42 million net increase in the value of contracts for future periods; and

- unrealized losses of $113 million in 2009, which included $101 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $12 million net decrease in the value of contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,068 MW at December 31, 2010 and four generating facilities with total net generating capacity of 2,535 MW at December 31, 2009. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

The following table summarizes the results of operations of our Other Operations segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 19	$ 23	$ (4)
Contracted and capacity	87	93	(6)
Realized value of hedges	13	43	(30)
Total realized gross margin	119	159	(40)
Unrealized gross margin	(19)	16	(35)
Total gross margin (excluding depreciation and amortization)	100	175	(75)
Operating Expenses:			
Operations and maintenance	219	86	133
Depreciation and amortization	41	28	13
Impairment losses	28	5	23
Gain on sales of assets, net	(1)	(4)	3
Total operating expenses, net	287	115	172
Operating income (loss)	$ (187)	$ 60	$ (247)

Gross Margin

The decrease of $40 million in realized gross margin was principally a result of the following:

- a decrease of $30 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $13 million and $43 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for fuel exceeded market prices for fuel;

a decrease of $6 million in contracted and capacity primarily related to decreases in capacity prices and megawatts of capacity sold; and

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- a decrease of $4 million in energy primarily as a result of a decrease in generation volumes from our oil-fired intermediate units at our Canal generating facility as a result of transmission upgrades in 2009, a decrease in the average settlement price for power and unplanned outages in 2010, offset in part by an increase in generation volumes at our Bowline generating facility.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $19 million in 2010 as a result of the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $16 million in 2009, which included a $65 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices, partially offset by $49 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $172 million in operating expenses was principally the result of the following:

- an increase of $133 million in operations and maintenance expense primarily related to the following:

  - an increase of $114 million in Merger-related costs incurred in 2010, which includes $67 million of advisory and legal costs and $35 million related to severance;

  - an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, comprised of a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See notes 13 and 16 to our consolidated financial statements; and

  - an increase of $24 million related to the accelerated vesting of Mirant's stock-based compensation as a result of the Merger; partially offset by

  - a decrease of $37 million primarily as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees. See note 8 to our consolidated financial statements;

  - a decrease of $20 million primarily related to lower property taxes because of a lower assessed value for the Lovett generating facility which was demolished in 2009 and a decrease in shutdown costs associated with this generating facility; and

  - a decrease of $12 million related to severance and stock-based compensation costs not related to the Merger primarily as a result of the departure of certain executives in 2009.

- an increase of $23 million in impairment losses. In 2010, we recognized $28 million in impairment losses for capitalized interest recorded at GenOn North America related to the Dickerson and Potomac River generating facilities. In 2009, we recognized $5 million in impairment losses for capitalized interest recorded at GenOn North America related to the Potomac

River generating facility;

an increase of $13 million in depreciation and amortization expense primarily as a result of the depreciation of interest capitalized at GenOn North America related to the scrubbers at our Maryland generating facilities that were placed in service in December 2009 and revisions to the useful lives of our assets as a result of a depreciation study completed in the first quarter of 2010; and

- a decrease of $3 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Financial Condition

Liquidity and Capital Resources

Management thinks that our liquidity position and cash flows from operations will be adequate to fund operating, maintenance and capital expenditures, to fund debt service and to meet other liquidity requirements. Management regularly monitors our ability to fund our operating, financing and investing activities. See note 6 to our consolidated financial statements for additional discussion of our debt. At December 31, 2011, we were in compliance with our debt covenants.

Sources of Funds and Capital Structure

Maintaining sufficient liquidity in our business is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we plan on a prospective basis for the expected liquidity requirements of our business considering the factors listed below:

- expected expenditures with respect to maintenance activities and capital improvements, and related outages;
- expected collateral postings in support of our business;
- effects of market price volatility on the amount of collateral postings for hedge transactions and risk management transactions;
- effects of market price volatility on fuel pre-payment requirements;
- seasonal and intra-month working capital requirements;
- the development and construction of new generating facilities, including GenOn Marsh Landing;
- debt service obligations; and
- costs associated with litigation, regulatory and tax proceedings.

The principal sources of our liquidity are expected to be: (a) existing cash on hand and expected cash flows from the operations of our subsidiaries, (b) letters of credit issued or borrowings made under the GenOn senior secured revolving credit facility and (c) letters of credit issued or borrowings made under the GenOn Marsh Landing project financing.

Our operating cash flows may be affected by, among other things: (a) demand for electricity; (b) the difference between the cost of fuel used to generate electricity and the market value of the electricity generated; (c) commodity prices (including prices for electricity, emissions allowances, natural gas, coal and oil); (d) operations and maintenance expenses in the ordinary course; (e) planned and unplanned outages; (f) terms with trade creditors; and (g) cash requirements for capital expenditures relating to certain facilities (including those necessary to comply with environmental regulations).

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The table below sets forth total cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at December 31, 2011 (in millions):

Cash and Cash Equivalents:	
GenOn (excluding GenOn Mid-Atlantic and REMA)	$ 1,571
GenOn Mid-Atlantic	68
REMA(1)	29
Total cash and cash equivalents	1,668
Less: cash reserved for other purposes	(13)
Total available cash and cash equivalents	1,655
Availability under GenOn credit facilities(2)	523
Total available cash, cash equivalents and availability under GenOn credit facilities(1)	$ 2,178

(1) At December 31, 2011, REMA did not satisfy the restricted payments test and therefore could not use such funds to distribute cash and make other restricted payments.

(2) Availability under the GenOn credit facilities does not include availability under the GenOn Marsh Landing credit facility.

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2011, except for amounts held in bank accounts to cover current payables, all of our cash and cash equivalents were invested in AAA-rated United States Treasury money market funds.

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We and certain of our subsidiaries, including GenOn Americas Generation, are holding companies. The chart below is a summary representation of our capital structure and is not a complete corporate organizational chart.

(1)

The GenOn credit facilities are guaranteed by certain direct and indirect subsidiaries of GenOn excluding GenOn Americas Generation; provided, however, that certain of GenOn Americas Generation's subsidiaries (other than GenOn Mid-Atlantic and GenOn Energy Management and their subsidiaries) guarantee the GenOn credit facilities to the extent permitted under the indenture for the senior notes of GenOn Americas Generation. GenOn Americas is a co-borrower under the GenOn credit facilities and the term loan balance is recorded at GenOn Americas.

(2) At December 31, 2011, the present values of lease payments under the GenOn Mid-Atlantic and REMA operating leases were approximately $881 million and $466 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination values of the GenOn Mid-Atlantic and REMA operating leases were $1.3 billion and $735 million, respectively.

(3) At December 31, 2011, $33 million and $74 million were outstanding under the GenOn Marsh Landing senior secured term loan, due 2017 and senior secured term loan, due 2023, respectively. See "GenOn Marsh Landing Credit Facility" below for discussion.

Except for existing cash on hand, GenOn and GenOn Americas Generation are holding companies that are dependent on the distributions and dividends of their subsidiaries for liquidity. A substantial portion of cash from our operations is generated by GenOn Mid-Atlantic.

The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At December 31, 2011, GenOn Mid-Atlantic satisfied the restricted payments tests. At December 31, 2011, REMA did not satisfy the restricted payments test. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $165.6 million of cash (which is included in funds on deposit on the consolidated balance sheet) in respect of such liens. See note 6 to our consolidated financial statements.

Pursuant to the terms of their respective lease and debt documents, GenOn Mid-Atlantic, REMA and GenOn Marsh Landing are restricted from, among other actions, (a) encumbering assets, (b) entering into business combinations or divesting assets, (c) incurring additional debt, (d) entering into transactions with affiliates on other than an arm's length basis or (e) materially changing their business. Therefore, at December 31, 2011 and 2010, all of GenOn Mid-Atlantic's, REMA's and GenOn Marsh Landing's net assets (excluding cash) were deemed restricted for purposes of Rule 4-08(e)(3)(ii) of Regulation S-X. The amounts of the deemed restricted net assets were as follows:

	December 31,	
	2011	**2010**
	(in millions)	
GenOn Mid-Atlantic	$ 3,859	$ 3,690
REMA	534	422
GenOn Marsh Landing	107	80
Total restricted net assets	$ 4,500	$ 4,192

The ability of GenOn Americas Generation to pay its obligations is dependent on the receipt of dividends from GenOn North America and, in turn, GenOn Mid-Atlantic; capital contributions or intercompany loans from GenOn; and its ability to refinance all or a portion of those obligations as they become due.

GenOn Marsh Landing Credit Facility

In October 2010, GenOn Marsh Landing entered into a credit agreement for up to approximately $650 million of commitments to provide construction and permanent financing for the Marsh Landing generating facility. The credit facility consists of a $155 million tranche A senior secured term loan facility, due 2017, a $345 million tranche B senior secured term loan facility, due 2023, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing's debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing's collateral requirements under its PPA with PG&E. During the second quarter of 2011, we satisfied the required initial equity contributions of $147 million and GenOn Marsh Landing began borrowing under its credit facility. At December 31, 2011, GenOn Marsh Landing had $33 million and $74 million outstanding under tranche A of its senior secured term loan, due 2017 and tranche B of its senior secured tem loan, due 2023, respectively. Prior to the commercial operation date of the project, the collateral requirements under the PPA and construction contracts are being met by a $165 million cash collateralized letter of credit facility entered into by GenOn Energy Holdings on behalf of GenOn Marsh Landing in September 2010. At or near the commercial operation date of the project, the GenOn Energy Holdings cash collateralized letter of credit facility will terminate.

The term loans are to be fully amortized by their maturity dates. The tranche A term loan matures on December 31, 2017 and the tranche B term loan matures on the date that is the earlier of the last day of the first fiscal quarter following the tenth anniversary of the conversion of the credit facility from a construction facility to a permanent facility upon commercial operation of the Marsh Landing project and December 31, 2023. The expiry date of the letters of credit is December 31, 2017. Interest on the tranche A term loan is based on a base rate or a LIBOR rate plus an initial applicable margin of 1.5% for base rate loans and 2.5% for LIBOR loans (with such margin increasing 0.25% every three years). Interest on the tranche B term loan is based on a base rate or a LIBOR rate plus an initial applicable margin of 1.75% for base rate loans and 2.75% for LIBOR loans (with such margin increasing 0.25% every three years). Fees on lenders' exposure under the letters of credit accrue at a rate equal to the applicable margin payable on the tranche A term loan that is based on the LIBOR rate. An undrawn commitment fee applies at a rate of 0.75% per annum.

In connection with the credit agreement, GenOn Marsh Landing entered into interest rate swaps to mitigate the interest rate risks with respect to its term loans. GenOn Energy Holdings provided limited guarantees in respect of the interest rate swaps. The effective interest rate that GenOn Marsh Landing will pay for the term loans from the commercial operations date is 5.91% (plus the step-up in margin over time). The interest rate swaps are accounted for as cash flow hedges with changes in fair value recognized in other comprehensive income, with the exception of any ineffectiveness, which is recognized in the consolidated statement of operations. GenOn expects the interest rate swaps to remain highly effective in mitigating the interest rate risk.

Uses of Funds

Our requirements for liquidity and capital resources, other than for the day-to-day operation of our generating facilities, are significantly influenced by the following items: (a) capital expenditures, including capital expenditures to meet environmental regulations (b) debt service, (c) payments under the GenOn Mid-Atlantic and REMA operating leases, (d) collateral required for our asset management, hedging and proprietary trading and fuel oil management activities and (e) the development and construction of new generating facilities, in particular the GenOn Marsh Landing generating facility.

Capital Expenditures. Our capital expenditures, excluding capitalized interest, during 2011, were $436 million. Our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for 2012 and 2013 are $637 million and $327 million, respectively. See above under, "Capital Expenditures and Capital Resources" for further discussion of our capital expenditures.

Debt Service. At December 31, 2011, we had $4.1 billion of long-term debt ($10 million of which was classified as current) with expected interest payments of $350 million for 2012. See note 6 to our consolidated financial statements.

GenOn Mid-Atlantic Operating Leases. GenOn Mid-Atlantic leases a 100% interest in both the Dickerson and Morgantown baseload units and associated property through 2029 and 2034, respectively. GenOn Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. We are accounting for these leases as operating leases. Although there is variability in the scheduled payment amounts over the lease term, we recognize rent expense for these leases on a straight-line basis in accordance with GAAP. Rent expense under the GenOn Mid-Atlantic leases was $96 million for each of 2011, 2010 and 2009. The scheduled payment amounts for the GenOn Mid-Atlantic leases are $132 million and $138 million for 2012 and 2013, respectively. At December 31, 2011, the total notional minimum lease payments for the remaining term of the leases aggregated $1.6 billion and the aggregate termination value for the leases was approximately $1.3 billion and generally decreases over time. In addition, the present value of lease payments at December 31, 2011 was approximately $881 million (assuming a 10% discount rate). GenOn provides letters of credit in support of GenOn Mid-Atlantic's lease obligations to post rent reserves in an aggregate amount equal to the greatest of the next six months scheduled rent payments, 50% of the next 12 months scheduled rent payments or $75 million.

REMA Operating Leases. REMA leases 16.45% and 16.67% interests in the Conemaugh and Keystone baseload facilities, respectively through 2034 and we expect to make payments through 2029. REMA also leases a 100% interest in the Shawville baseload facility through 2026 and we expect to make payments through that date. At the expiration of these leases, there are several renewal options related to fair value. We are accounting for these leases as operating leases and recognize rent expense on a straight-line basis of $35 million per year. Rent expense totaled $35 million and $3 million during 2011 and December 2010. The scheduled payment amounts for the REMA leases are $56 million and $64 million for 2012 and 2013, respectively. At December 31, 2011, the total notional minimum lease payments for the remaining term of the leases aggregated $818 million and the aggregate termination value for the leases was approximately $735 million and generally decreases over time. In addition, the present value of lease payments at December 31, 2011 was approximately $466 million (assuming a 9.4% discount rate). GenOn provides letters of credit in support of REMA's lease obligations to post rent reserves in an aggregate amount equal to the greater of the next six months scheduled rent payment or 50% of the next 12 months scheduled rent payments. See note 10 to our consolidated financial statements for further discussion on letters of credit.

See "Business Segments Western PJM/MISO Segment" in Item 1 and "Risk Factors" in Item 1A of this form 10-K for a discussion of our leased Shawville coal-fired generating facility and our plans to place it in long-term protective layup in April 2015.

Cash Collateral, Letters of Credit and Surety Bonds. In order to sell power and purchase fuel in the forward markets and perform other energy trading and marketing activities, we often are required to provide credit support to our counterparties or make deposits with brokers. In addition, we often are required to provide cash collateral, letters of credit, surety bonds or financial guarantees as credit support for various contractual and other obligations incurred in connection with our commercial and operating activities, including obligations in respect of transmission and interconnection access, participation in power pools, rent reserves, power purchases and sales, fuel and emission purchases and sales, construction and equipment purchases and other operating activities. In the event that we default, the counterparty can draw on a letter of credit or surety bond or apply cash collateral held to satisfy

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the existing amounts outstanding under an open contract. At December 31, 2011, we had $224 million of posted cash collateral and $265 million of letters of credit outstanding under our revolving credit facility, primarily to support our asset management activities, trading activities, rent reserve requirements, Marsh Landing project and other commercial arrangements. In addition, we issued $131 million of cash-collateralized letters of credit in support of the Marsh Landing project and delivered $46 million of surety bonds to satisfy various credit support requirements. Our liquidity requirements are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility, credit terms with third parties and regulation of energy contracts. See Item 1, "Business" for our discussion on the Dodd-Frank Act. See note 10 to our consolidated financial statements.

The following table summarizes cash collateral posted with counterparties and brokers, letters of credit issued and surety bonds provided:

	December 31,	
	2011	**2010**
	(in millions)	
Cash collateral posted energy trading and marketing	$ 185	$ 220
Cash collateral posted other operating activities	39	45
Letters of credit Marsh Landing project[1]	175	106
Letters of credit rent reserves	130	133
Letters of credit energy trading and marketing	59	96
Letters of credit other operating activities	32	38
Surety bonds[2]	46	50
Total	$ 666	$ 688

(1) Includes $131 million and $106 million of cash-collateralized letters of credit at December 31, 2011 and December 31, 2010, respectively.

(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

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Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Our debt obligations, off-balance sheet arrangements and contractual obligations at December 31, 2011, are as follows:

	Total	Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations by Year Less than One Year	One to Three Years	Three to Five Years	More than Five Years
			(in millions)		
Long-term debt	$ 6,956	$ 362	$ 1,287	$ 629	$ 4,678
GenOn Mid-Atlantic operating leases	1,596	132	269	260	935
REMA operating leases	818	56	128	117	517
Other operating leases	161	35	45	38	43
Fuel commitments	942	636	306		
Commodity transportation commitments	533	68	115	122	228
LTSA commitments	549	23	42	41	443
Maryland Healthy Air Act	83	83			
GenOn Marsh Landing	347	299	48		
Pension funding obligations	181	25	71	65	20
Other	529	318	41	30	140
Total payments	$ 12,695	$ 2,037	$ 2,352	$ 1,302	$ 7,004

Our contractual obligations table does not include our derivative obligations reported at fair value (other than fuel supply commitments), which are discussed in note 4 to our consolidated financial statements and asset retirement obligations, which are discussed in note 5 to our consolidated financial statements.

Long-term debt includes the current portion of long-term debt and long-term debt on our consolidated balance sheets, which are discussed in note 6 to our consolidated financial statements. Long-term debt also includes estimated interest on debt. Interest on our variable interest debt is based on the LIBOR curve at December 31, 2011. These amounts do not include any fair value adjustments or unamortized debt discounts or premiums.

GenOn Mid-Atlantic operating leases relate to our minimum lease payments associated with our off-balance sheet leases of the Dickerson and Morgantown baseload units. REMA operating leases relate to our minimum lease payments associated with our off-balance sheet leases of a 16.45% interest in the Conemaugh facility, a 16.67% interest in the Keystone facility and a 100% interest in the Shawville facility. In addition, we have commitments under other operating leases with various terms and expiration dates.

Fuel and commodity transportation commitments primarily relate to coal agreements and commodity transportation agreements.

Long-term service agreements relate to contracts that cover some periodic maintenance, including parts, on power generation turbines. The long-term service agreements terminate from 2014 to 2038 based on turbine usage.

Maryland Healthy Air Act commitments reflect the remaining expected payments for capital expenditures to comply with the limitations for SO_2, NO_x and mercury emissions under the Maryland Healthy Air Act. We completed the installation of the remaining pollution control equipment related to compliance with the Maryland Healthy Air Act in the fourth quarter of 2009. However, provisions in our construction contracts provide that certain payments be made after final completion of the project.

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GenOn Marsh Landing development project reflects the current projected commitments related to our construction of the Marsh Landing generating facility.

Pension funding obligations represent our estimated pension contributions based on assumptions that are subject to change. We have estimated projected funding requirements through 2021.

Other primarily represents the open purchase orders less invoices received related to general procurement of products and services purchased in the ordinary course of business. These include construction, maintenance and labor activities at our generating facilities. Other also includes liabilities related to the accounting for uncertainty in income taxes and miscellaneous liabilities.

Historical Cash Flows

2011 Compared to 2010

Continuing Operations

Operating Activities. Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities from continuing operations increased by $66 million during 2011, compared to 2010, primarily as a result of the following:

- *Realized gross margin.* An increase in cash provided of $389 million in 2011 compared to 2010 (excluding an out-of-market contract amortization of $33 million in 2011 and lower of cost or market inventory adjustments of $9 million) primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger. See "Results of Operations" in this Item 7 for additional discussion of our performance in 2011 compared to 2010;

- *Accounts payable, collateral.* An increase in cash provided of $144 million primarily as a result of $122 million posted by our counterparties in 2011 compared to $22 million returned to our counterparties in 2010;

- *Funds on deposit.* An increase in cash provided of $59 million primarily as a result of $17 million of additional collateral returned by our counterparties in 2011 compared to $42 million of additional collateral posted with our counterparties in 2010;

- *Inventories.* An increase in cash provided of $44 million primarily related to changes in fuel oil inventory compared to 2010; and

- *Other operating assets and liabilities.* An increase in cash provided of $14 million related to changes in other operating assets and liabilities compared to 2010.

The increase in cash provided by operating activities from continuing operations was partially offset by the following:

- *Operating expenses.* An increase in cash used related to higher operations and maintenance expense of $464 million primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger and an increase in Merger-related costs. See "Results of Operations" in this Item 7 for additional discussion of our performance in 2011 compared to 2010; and

- *Interest expense.* An increase in cash used of $120 million primarily as a result of debt assumed in the Merger and new debt issued as a result of the Merger. See note 6 to our consolidated financial statements.

Discontinued Operations. During 2010, net cash provided by operating activities from discontinued operations was primarily from the sale of transmission credits from our previously owned Wrightsville generating facility.

Investing Activities. Net cash provided by investing activities increased by $2.142 billion during 2011 compared to 2010. This difference was primarily a result of the following:

Withdrawals from restricted funds on deposit. An increase in cash provided of $1.625 billion primarily related to funds received from the GenOn debt financing on December 3, 2010, which were subsequently placed in restricted deposits at December 31, 2010. The withdrawal of cash was used to repay long-term debt. See note 6 to our consolidated financial statements;

Payments into restricted funds on deposit. An increase in cash provided of $1.344 billion is principally a result of $1.545 billion of funds placed in escrow related to the discharge of the GenOn senior secured notes and GenOn North America senior notes and the defeasance of the PEDFA fixed-rate bonds in 2010. The increase was partially offset by $242 million primarily related to funds placed in restricted deposits as a result of our scrubber contract litigation and related liens in 2011. See notes 6 and 16 to our consolidated financial statements;

Other investing. An decrease in cash used of $22 million primarily related to the funding of the Rabbi Trusts established during 2010 to fund severance and non-qualified deferred compensation plans for certain key employees in connection with the Merger; and

Proceeds from the sales of assets. An increase in cash provided of $14 million primarily related to proceeds received from the sale of investments.

The increase in cash provided by and decrease in cash used in investing activities was partially offset by the following:

Cash acquired from RRI Energy, Inc. A decrease in cash provided of $717 million as a result of the Merger. See note 2 to our consolidated financial statements; and

Capital expenditures. An increase in cash used of $146 million primarily related to the construction of our Marsh Landing generating facility, partially offset by a decrease in cash used as a result of payments related to our Maryland scrubber projects.

Financing Activities. Net cash used in financing activities increased by $3.385 billion during 2011 compared to 2010. This difference was primarily a result of the $1.699 billion repayment of debt during 2011 and $1.804 billion of debt issued in 2010 in connection with the Merger and GenOn Marsh Landing debt issuance costs, partially offset by proceeds received of $107 million to finance the construction of our Marsh Landing generating facility. See note 6 to our consolidated financial statements.

2010 Compared to 2009

Continuing Operations

Operating Activities. Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities from continuing operations decreased by $614 million during 2010, compared to 2009, primarily as a result of the following:

Operating expenses. An increase in cash used for operations and maintenance expense of $228 million primarily related to the Merger costs, the operation of the scrubbers at our Maryland generating facilities in 2010 and the 2009 MC Asset Recovery settlement. In 2009, we were reimbursed $52 million of cash as a result of the MC Asset Recovery settlement with Southern Company for funds that we provided to MC Asset Recovery and costs that we incurred related to MC Asset Recovery that had not been previously reimbursed. See "Results of Operations" in this Item 7 for additional discussion of our performance in 2010 compared to 2009;

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Realized gross margin. A decrease in cash provided of $213 million in 2010, compared to 2009, excluding a decrease in non-cash lower of cost or market fuel inventory adjustments of $10 million. See "Results of Operations" in this Item 7 for additional discussion of our performance in 2010 compared to 2009;

Interest payments, net of amounts capitalized. An increase in cash used of $120 million primarily as a result of a decrease in capitalized interest (which is included in investing activities) and additional interest payments associated with the debt assumed in connection with the Merger;

Funds on deposit. An increase in cash used of $63 million primarily as a result of postings of $42 million during 2010 compared to $21 million returned by our counterparties during 2009;

Inventories. An increase in cash used of $30 million primarily as a result of higher prices and purchases of a larger volume of fuel oil; and

Receivables and accounts payable and accrued liabilities, net. An increase in cash used of $25 million primarily related to a $49 million increase in receivables outstanding subsequent to the Merger, partially offset by a $21 million decrease in cash collateral returned to our counterparties during 2010 compared to 2009 and a $9 million decrease in cash used for settlement of bankruptcy related claims and expenses.

The increases in cash used in and decreases in cash provided by operating activities were partially offset by the following:

Other operating assets and liabilities. A decrease in cash used of $47 million primarily related to a decrease in property tax payments, income tax payments and prepaid property and general liability insurance during 2010 compared to 2009.

Discontinued Operations

During 2010 and 2009, net cash provided by operating activities from discontinued operations was primarily from the sale of transmission credits from our previously owned Wrightsville generating facility.

Investing Activities. Net cash used in investing activities increased by $520 million during 2010 compared to 2009. This difference was primarily a result of the following:

Payments into restricted funds on deposit. An increase in cash used of $1.586 billion, primarily related to funds placed in restricted deposits as a result of the discharge of the GenOn senior secured notes and GenOn North America senior notes and the defeasance of the PEDFA fixed-rate bonds. See note 6 to our consolidated financial statements;

Other investing. An increase in cash used of $46 million primarily related to the funding of the Rabbi Trusts established during 2010 to fund severance payments and non-qualified deferred compensation plans for certain key employees in connection with the Merger; and

Proceeds from the sales of assets. A decrease in cash provided of $22 million primarily related to the sales of emissions allowances in 2009 as compared to 2010.

The increases in cash used and decrease in cash provided by investing activities were partially offset by the following:

Cash acquired from RRI Energy, Inc. An increase in cash provided of $717 million as a result of the Merger. See note 2 to our consolidated financial statements;

Capital expenditures. A decrease in cash used of $372 million primarily related to placing scrubbers for our Maryland generating facilities in service during 2009 as part of our compliance with the Maryland Healthy Air Act; and

Withdrawals from restricted funds on deposit. An increase in cash provided of $40 million primarily related to withdrawals from the escrow account for the payment of accrued interest on debt to be discharged.

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Financing Activities. Net cash provided by financing activities increased by $1.464 billion during 2010 compared to 2009. This difference was primarily a result of the following:

- *Proceeds from long-term debt.* An increase in cash provided of $1.896 billion primarily related to the issuance of $700 million senior secured term loan (issued at a discount for $693 million) and $1.225 billion senior unsecured notes (issued at discount for $1.203 billion); partially offset by

- *Repayment of long-term debt.* An increase in cash used of $334 million primarily related to the repayment of the GenOn North America senior secured term loan; and

- *Debt issuance costs.* An increase in cash used of $92 million related to $68 million of costs paid for the issuance of debt in connection with the Merger and $24 million of costs paid in connection with entering into the GenOn Marsh Landing credit facility.

Critical Accounting Estimates

The accounting policies described below are considered critical to obtaining an understanding of our consolidated financial statements because their application requires significant estimates and judgments by management in preparing our consolidated financial statements. Management's estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the following conditions apply:

- the estimate requires significant assumptions; and

- changes in the estimate could have a material effect on our consolidated results of operations or financial condition; or

- if different estimates that could have been selected had been used, there could be a material effect on our consolidated results of operations or financial condition.

We have discussed the selection and application of these accounting estimates with the Audit Committee of the Board of Directors and our independent registered public accounting firm. It is management's view that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions. The sections below contain information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop the estimates.

Revenue Recognition and Accounting for Energy Trading and Marketing Activities

Nature of Estimates Required. Accounting standards require an accrual model to be used to account for our revenues from the sale of energy, capacity and ancillary services. We recognize revenue when it has been earned and collection is probable as a result of electricity delivered or capacity available to customers pursuant to contractual commitments that specify volume, price and delivery requirements. Sales of energy primarily are based on economic dispatch, or they may be 'as-ordered' by an ISO or RTO, based on member participation agreements, but without an underlying contractual commitment. ISO and RTO revenues and revenues for sales of energy based on economic dispatch are recorded on the basis of MWh delivered, at the relevant day-ahead or real-time prices. The accrual model is also used to account for our revenues from the sales of natural gas. These sales are sold at market-based prices through third party contracts. Sales that have been delivered but not billed by period end are estimated.

Accounting standards require a fair value model to be used to measure fair value on a recurring basis for derivative energy contracts that are used to manage our exposure to commodity price risk or that are used in our proprietary trading and fuel oil management activities. We use a variety of derivative financial instruments, such as futures, forwards, swaps and option contracts, in the

management of our business. Such derivative financial instruments have varying terms and durations, or tenors, which range from a few days to a number of years, depending on the instrument.

Derivative financial instruments are recorded in our consolidated financial statements at fair value as either derivative contract assets or derivative contract liabilities, with changes in fair value recognized currently in income unless we have elected to apply cash flow hedging or they qualify for a scope exception pursuant to the accounting guidance. Management considers fair value techniques and valuation adjustments related to credit and liquidity to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors. Transactions that are not accounted for using the fair value model under the accounting guidance for derivative financial instruments are either not derivatives or qualify for the scope exception and are accounted for under accrual accounting. We recognize immediately in income appropriate inception gains and losses for transactions at other than the bid price or ask price.

Key Assumptions and Approach Used. In determining fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair value measurement inputs we use vary from readily observable prices for exchange-traded and over-the-counter instruments (Level 1 or Level 2) to price curves that cannot be validated through external pricing sources (Level 3). Note 4 to our consolidated financial statements explains the fair value hierarchy. For most delivery locations and tenors where we have positions, we receive multiple independent broker price quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. If no active market exists, we estimate the fair value of certain derivative financial instruments using price extrapolation, interpolation and other quantitative methods. We have not identified any distressed market conditions that would alter our valuation techniques at December 31, 2011. Fair value estimates involve uncertainties and matters of significant judgment. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. Our assets and liabilities classified as Level 3 in the fair value hierarchy represent approximately 4% of our total assets and 11% of our total liabilities measured at fair value at December 31, 2011.

The fair value of derivative contract assets and liabilities in our consolidated balance sheets is also affected by our assumptions as to time value, credit risk and non-performance risk. The nominal value of the contracts is discounted using a forward interest rate curve based on LIBOR. In addition, the fair value of our derivative contract assets is reduced to reflect the estimated default risk of counterparties on their contractual obligations to us. The default risk of our counterparties for a significant portion of our overall net position is measured based on published spreads on credit default swaps. The fair value of our derivative contract liabilities is reduced to reflect our estimated risk of default on our contractual obligations to counterparties and is measured based on published default rates of our debt. The credit risk reflected in the fair value of our derivative contract assets and the non-performance risk reflected in the fair value of our derivative contract liabilities are calculated with consideration of our master netting agreements with counterparties and our exposure is reduced by cash collateral posted to us against these obligations.

Effect if Different Assumptions Used. The amounts recorded as revenue or cost of fuel, electricity and other products change as estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control. Because we use derivative financial instruments and have not elected cash flow or fair value hedge accounting for the majority of our derivative financial instruments, certain components of our financial statements, including gross margin,

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operating income and balance sheet ratios, are at times volatile and subject to fluctuations in value primarily as a result of changes in forward energy and fuel prices. Significant negative changes in fair value could require us to post additional collateral either in the form of cash or letters of credit. Because the fair value measurements of our material assets and liabilities are based on observable market information, there is not a significant range of values around the fair value estimate. For our derivative financial instruments that are measured at fair value using quantitative pricing models, a significant change in estimate could affect our results of operations and cash flows at the time contracts are ultimately settled. The estimated fair value of our derivative contract assets and liabilities was a net asset of $881 million at December 31, 2011. A 10% change in electricity and fuel prices would result in approximately a $196 million change in the fair value of our net asset at December 31, 2011. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" for further sensitivities in our assumptions used to calculate fair value. See note 4 to our consolidated financial statements for further information on derivative financial instruments related to energy trading and marketing activities.

Income Taxes and Deferred Tax Asset Valuation Allowance

Nature of Estimates Required. We currently record a tax provision for state and federal income taxes including any alternative minimum tax as applicable. We also recognize deferred tax assets and liabilities based on the difference between the balance sheet carrying amounts and the tax basis of the assets and liabilities. We must assess the likelihood that our deferred tax assets will be recoverable based on expected future taxable income. To the extent that we determine it is more-likely-than-not (greater than a 50% probability) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. See note 7 to our consolidated financial statements.

Key Assumptions and Approach Used. Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

At December 31, 2011, our deferred tax assets reduced by the valuation allowance are completely offset by our deferred tax liabilities. Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. We evaluate this position and make our judgment based on the facts and circumstances at that time. We think that the realization of future taxable income sufficient to utilize existing deferred tax assets is less than more-likely-than-not at this time. The primary factors related to this conclusion are as follows:

- The prices for power and natural gas are low compared to several years ago and have resulted in a decrease in the forecasted gross margin for our generating facilities.

- Weak market conditions have resulted in a decrease in the forecasted gross margin of our generating facilities.

Under the accounting guidance for the uncertainty of income taxes, we must reflect in our income tax provision the full benefit of all positions that will be taken in our income tax returns, except to the extent that such positions are uncertain and fall below the recognition requirements of the guidance. In the event that we determine that a tax position meets the uncertainty criteria, an additional liability or an adjustment to our NOLs, determined under the measurement criteria of the guidance will result. This liability or adjustment is referred to as an unrecognized tax benefit. We periodically reassess the tax positions reflected in our tax returns for open years based on the latest information available and determine whether any portion of the tax benefits reflected therein should be treated as unrecognized. The amount of the unrecognized tax benefit requires management to make significant assumptions about the expected outcomes of certain tax positions included in our filed or yet to be filed tax returns.

Effect if Different Assumptions Used. At the Merger, each of Mirant and RRI Energy separately determined whether or not each had experienced an ownership change as defined in IRC § 382. IRC § 382 provides, in general, that an ownership change occurs when there is a greater than 50-percentage point increase in ownership of a company's stock held by new or existing stockholders who own (or are deemed to own under IRC § 382) 5% or more of the loss company's stock over a three year testing period. IRC § 382 limits the amount of pre-merger NOLs that can be used during any post-ownership change year to offset taxable income. Based on information contained in a shareholder's recent filing made pursuant to SEC Regulation 13G and subsequent inquiries made on the basis of such information, it is possible RRI Energy may have experienced an ownership change as defined above as a result of the Merger. As of this date we have not completed verification of the change and we continue to seek "actual knowledge" with respect to certain facts pertaining to the possible ownership change. Should we determine that RRI Energy had an ownership change at the Merger date, its NOLs would be substantially limited to reflect the requirements of IRC § 382. Prior to the Merger, RRI Energy received guidance from the Internal Revenue Service that specified the methodology to be used in determining whether an ownership change had occurred under circumstances when a stockholder owns interests in each of the merging companies immediately prior to the Merger. Our initial analysis had concluded that sufficient overlapping stockholders of Mirant and RRI Energy existed immediately prior to the Merger such that the Merger did not cause an ownership change for RRI Energy. Therefore, RRI Energy's pre-merger NOLs were not adjusted for any IRC § 382 limitation as a result of the Merger. Mirant experienced an ownership change as a result of the Merger. We have reduced the amount of the Mirant NOLs available to offset post-merger taxable income based on the limits determined in accordance with IRC § 382.

We continue to be under audit for multiple years by taxing authorities in various jurisdictions. Considerable judgment is required to determine the tax treatment of particular items that involve interpretations of complex tax laws. A tax liability is recorded for filing positions with respect to which the outcome is uncertain and the recognition criteria under the accounting guidance for uncertainty in income taxes has been met. Such liabilities are based on judgment and it can take many years to resolve a recorded liability such that the related filing position is no longer subject to question. We have not recorded a liability for those proposed tax adjustments related to the current tax audits where we continue to think that our filing position meets the more-likely-than-not threshold prescribed in the accounting guidance related to accounting for uncertainty in income taxes. Any adverse outcomes arising from these matters could result in a material change in the amount of our deferred taxes.

Long-Lived Assets

Estimated Useful Lives

Nature of Estimates Required. The estimated useful lives of our long-lived assets are used to compute depreciation expense, determine the carrying value of asset retirement obligations and estimate expected future cash flows attributable to an asset for the purposes of impairment testing. Estimated useful lives are based, in part, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly.

Key Assumptions and Approach Used. Estimated useful lives are the mechanism by which we allocate the cost of long-lived assets over the asset's service period. We perform depreciation studies periodically to update changes in estimated useful lives. The actual useful life of an asset could be affected by changes in estimated or actual commodity prices, environmental regulations, various legal

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factors, competitive forces and our liquidity and ability to sustain required maintenance expenditures and satisfy asset retirement obligations. We use composite depreciation for groups of similar assets and establish an average useful life for each group of related assets. In accordance with the accounting guidance related to evaluating long-lived assets for impairment, we cease depreciation on long-lived assets classified as held for sale. Also, we may revise the remaining useful life of an asset held and used subject to impairment testing. See note 5 to our consolidated financial statements.

Effect if Different Assumptions Used. The determination of estimated useful lives is dependent on subjective factors such as expected market conditions, commodity prices and anticipated capital expenditures. Since composite depreciation rates are used, the actual useful life of a particular asset may differ materially from the useful life estimated for the related group of assets. A 10% increase in the weighted average useful lives of our facilities would result in a $28 million decrease in annual depreciation expense. A 10% decrease in the weighted average useful lives of our facilities would result in a $34 million increase in annual depreciation expense. In the event the useful lives of significant assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities recognized for future asset retirement obligations may be insufficient and impairments in the carrying value of tangible and intangible assets may result.

Asset Impairments

Nature of Estimates Required. We evaluate our long-lived assets, including intangible assets, for impairment in accordance with applicable accounting guidance. The amount of an impairment charge is calculated as the excess of the asset's carrying value over its fair value, which generally represents the discounted expected future cash flows attributable to the asset, or in the case of an asset we expect to sell, at its fair value less costs to sell.

The accounting guidance related to impairments of long-lived assets requires management to recognize an impairment charge if the sum of the undiscounted expected future cash flows from a long-lived asset or definite-lived intangible asset is less than the carrying value of that asset. We evaluate our long-lived assets (property, plant and equipment) and definite-lived intangible assets for impairment whenever indicators of impairment exist or when we commit to sell the asset. These evaluations of long-lived assets and definite-lived intangible assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operational analyses. If the carrying amount is not recoverable, an impairment charge is recorded.

The prices for power and natural gas are low compared to several years ago. The energy gross margin from our baseload coal units is negatively affected by these price levels. Additionally, weak market conditions and various demand-response programs have resulted in a decrease in the forecasted gross margin of our generating facilities. On an ongoing basis, we evaluate our long-lived assets for indications of impairment; however, given the remaining useful lives for many of our generating facilities, the total undiscounted cash flows for these generating facilities are more significantly affected by the long-term view of supply and demand than by the short term fluctuations in energy prices and demand. As such, we typically do not consider short term decreases in either energy prices or demand to cause an impairment evaluation. Our current expectation is that there will be a recovery in gross margins over time as a result of declining reserve margins in the markets in which we operate such that companies constructing new generating facilities can earn a reasonable rate of return on their investment. This implies that gross margins and therefore cash flows in the future will be better than they are currently because market prices will need to rise high enough to provide an incentive for new generating facilities to be built and the entire market will realize the benefit of those higher gross margins.

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Key Assumptions and Approach Used. The impairment evaluation is a two-step process, the first of which involves comparing the undiscounted cash flows to the carrying value of the asset. If the carrying value exceeds the undiscounted cash flows, the fair value of the asset must be calculated on a discounted basis. The fair value of an asset is the price that would be received from a sale of the asset in an orderly transaction between market participants at the measurement date. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, when available. In the absence of quoted prices for identical or similar assets, fair value is estimated using various internal and external valuation methods. These methods include discounted cash flow analyses and reviewing available information on comparable transactions. The determination of fair value requires management to apply judgment in estimating future capacity and energy prices, environmental and maintenance expenditures and other cash flows. Our estimates of the fair value of the assets include significant assumptions about the timing of future cash flows, remaining useful lives and the selection of a discount rate that represents the estimated weighted average cost of capital consistent with the risk inherent in future cash flows.

Our long-lived asset impairment assessments typically include assumptions about the following:

- electricity, fuel and capacity prices;
- costs related to compliance with environmental regulations;
- timing of announced transmission projects;
- timing and extent of generating capacity additions and deactivations; and
- future capital expenditure requirements related to the generating facilities.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether an impairment exists are subject to a high degree of uncertainty. The estimated fair value of an asset would change if different estimates and assumptions were used in our applied valuation techniques, including estimated undiscounted cash flows, discount rates and remaining useful lives for assets held and used. If actual results are not consistent with the assumptions used in estimating future cash flows and asset fair values, we may be exposed to additional losses that could be material to our results of operations. If our outlook for the wholesale energy market changes negatively, or if our ongoing evaluation of our business results in decisions to deactivate or dispose of facilities, we could have impairment charges related to our long-lived assets. Furthermore, increasing environmental regulatory requirements could result in facilities being removed from service or derated.

See "Business Segments" in Item 1 of this Form 10-K for a discussion of our expectations to deactivate some coal-fired generating facilities, of approximately 3,140 MWs, between 2012 and 2015. See also note 5 to our consolidated financial statements.

Loss Contingencies

Nature of Estimates Required. We record loss contingencies when it is probable that a liability has been incurred and the amount can be reasonably estimated. We consider loss contingency estimates to be critical accounting estimates because they entail significant judgment regarding probabilities and ranges of exposure, and the ultimate outcome of the proceedings is unknown and could have a material adverse effect on our results of operations, financial condition and cash flows. We currently have loss contingencies related to litigation, environmental matters, tax matters and others.

Key Assumptions and Approach Used. The determination of a loss contingency requires significant judgment as to the expected outcome of each contingency in future periods. In making the determination as to potential losses and probability of loss, we consider all available positive and negative evidence including the expected outcome of potential litigation. We record our best estimate of a loss, or the low end of our range if no estimate is better than another estimate within a range of estimates, when the loss is considered probable and can be reasonably estimated. As additional information becomes available, we reassess the potential liability related to the contingency and revise our estimates. In our evaluation of legal matters, we hold discussions with applicable legal counsel and rely on analysis of case law and legal precedents.

Effect if Different Assumptions Used. Revisions in our estimates of potential liabilities could materially affect our results of operations and the ultimate resolution may be materially different from the estimates that we make.

See notes 2, 7, 10 and 16 to our consolidated financial statements for additional information on our loss contingencies.

Litigation

We are currently involved in legal proceedings. We estimate the range of liability through discussions with applicable legal counsel and analysis of case law and legal precedents. We record our best estimate of a loss, or the low end of our range if no estimate is better than another estimate within a range of estimates, when the loss is considered probable and can be reasonably estimated. As additional information becomes available, we reassess the potential liability related to our pending litigation and revise our estimates. Revisions in our estimates of the potential liability could materially affect our results of operations and the ultimate resolution may be materially different from the estimates that we make.

See note 16 to our consolidated financial statements.

Recently Adopted Accounting Guidance

See note 1 to our consolidated financial statements for further information related to our recently adopted accounting guidance.

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Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

Fair Value Measurements

We are exposed to market risk, primarily associated with commodity prices. We also consider risks associated with interest rates and credit when valuing our derivative financial instruments.

The estimated net fair value of our derivative contract assets and liabilities was a net asset of $881 million and $720 million at December 31, 2011 and 2010, respectively. The following tables provide a summary of the factors affecting changes (composed of the sum of the quarterly changes) in fair value of the derivative contract asset and liability accounts for 2011 and 2010:

	Commodity Contracts		Other Contracts	
	Asset Management	Trading Activities	Interest Rate	Total
		(in millions)		
Fair value of portfolio of assets and liabilities at January 1, 2011	$ 706	$ (5)	$ 19	$ 720
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[1]	458	(4)	(51)	403
Purchases[2]				
Issuances[2]				
Settlements[3]	(248)	6		(242)
Fair value of portfolio of assets and liabilities at December 31, 2011	$ 916	$ (3)	$ (32)	$ 881
Fair value of portfolio of assets and liabilities at January 1, 2010	$ 701	$ 1	$	$ 702
Derivative contracts acquired and/or assumed in the Merger	49			49
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[1]	169	66	19	254
Roll off of previous values[4]	(340)	(49)		(389)
Purchases[2]				
Issuances[2]				
Settlements[5]	127	(23)		104
Fair value of portfolio of assets and liabilities at December 31, 2010	$ 706	$ (5)	$ 19	$ 720

(1) Represents the fair value, as of the end of each reporting period, of contracts entered into during each reporting period and the gains or losses attributable to contracts that existed as of the beginning of each reporting period and were still held at the end of each reporting period.

(2) Contracts entered into during each reporting period are reported with other changes in fair value.

(3) Effective January 1, 2011, represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each reporting period.

(4) Represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each reporting period.

(5) Represents the total cash settlements of contracts during each reporting period of contracts that existed at the beginning of each reporting period.

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In May 2010, we concluded that we could no longer assert that physical delivery is probable for many of our coal agreements. The conclusion was based on expected generation levels, changes observed in the coal markets and substantial progress in the construction of a coal blending facility at the Morgantown generating facility that would allow for greater flexibility of our coal supply. Because we can no longer assert that physical delivery of coal from these agreements is probable, we are required to apply fair value accounting for these contracts. The fair value of these derivative contracts is included in the tables above.

We did not elect the fair value option for any financial instruments under the accounting guidance. However, we do transact using derivative financial instruments which are required to be recorded at fair value in our consolidated balance sheets under the accounting guidance related to derivative financial instruments.

At December 31, 2011, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	2012	2013	2014	2015	2016	2017 and thereafter	Total fair value
				(in millions)			
Asset Management:							
Prices actively quoted (Level 1)	$ (29)	$ 14	$ 12	$ 17	$ 26	$	$ 40
Prices provided by other external sources (Level 2)	355	295	242	37			929
Prices based on models and other valuation methods (Level 3)	(43)	(11)		1			(53)
Total asset management	$ 283	$ 298	$ 254	$ 55	$ 26	$	$ 916
Trading Activities:							
Prices actively quoted (Level 1)	$ (18)	$	$	$	$	$	$ (18)
Prices provided by other external sources (Level 2)	(5)	(2)					(7)
Prices based on models and other valuation methods (Level 3)	20	2					22
Total trading activities	$ (3)	$	$	$	$	$	$ (3)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)	(1)	(7)	(10)	(6)	(4)	(4)	(32)
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$ (1)	$ (7)	$ (10)	$ (6)	$ (4)	$ (4)	$ (32)

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, volatility and credit risk. For further discussion of how we determine these fair values, see note 4 to our consolidated financial statements and "Management's Discussion and Analysis of Financial Condition and Results of Operations Recently Adopted Accounting Guidance and Critical Accounting Estimates Critical Accounting Estimates" in Item 7 of this Form 10-K.

Commodity Price Risk

In connection with our business of generating electricity, we are exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold and the fair value of our fuel inventories. A portion of our fuel requirements is purchased in the spot market and a portion of the electricity we produce is sold in the spot market. In addition, the open positions in our proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

The financial performance of our business of generating electricity is influenced by the difference between the variable cost of converting a fuel, such as natural gas, coal or oil, into electricity, and the variable revenue we receive from the sale of that electricity. The difference between the cost of a specific fuel used to generate one MWh of electricity and the market value of the electricity generated is commonly referred to as the "conversion spread." Absent the effects of our derivative contract activities, the operating margins that we realize are equal to the difference between the aggregate conversion spread and the cost of operating the facilities that produce the electricity sold.

Conversion spreads are dependent on a variety of factors that influence the cost of fuel and the sales price of the electricity generated over the longer term, including conversion spreads of other generating facilities in the regions in which we operate, facility outages, weather and general economic conditions. As a result of these influences, the cost of fuel and electricity prices do not always change in the same magnitude or direction, which results in conversion spreads for a particular generating facility widening or narrowing (or becoming negative) over any given period.

Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments, such as forward contracts, futures contracts, option contracts and financial swap agreements, to manage our exposure to commodity price risks. These contracts have varying terms and durations, which range from a few days to years, depending on the instrument. Our proprietary trading activities also utilize similar derivative contracts in markets where we have a physical presence to attempt to generate incremental gross margin. Our fuel oil management activities use derivative financial instruments to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products.

Derivative energy contracts that are required to be reflected at fair value are presented as derivative contract assets and liabilities in the consolidated balance sheets. The net changes in their fair market values are recognized in income in the period of change. As a result, our financial performance varies depending on changes in the prices of energy and energy-related commodities. The determination of fair value considers various factors, including closing exchange or OTC market price quotations, time value, credit quality, liquidity and volatility factors underlying options. See Item 7, "Critical Accounting Estimates" for the accounting treatment of our energy trading and marketing activities.

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a reserve, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $48 million and $21 million at December 31, 2011 and 2010, respectively.

In accordance with the fair value measurements accounting guidance, we calculate the credit reserve through consideration of observable market inputs, when available. We calculate our credit reserve using published spreads, where available, or proxies based upon published spreads, on credit default swaps for our counterparties applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. We do not, however, transact in credit default swaps or any other credit derivative. Potential loss exposure is calculated as our current exposure plus a calculated VaR over the remaining life of the contracts.

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Our non-collateralized power hedges entered into by GenOn Mid-Atlantic with financial institutions, which represent 37% of our net notional power position at December 31, 2011, are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Our coal contracts included in derivative contract assets and liabilities in the consolidated balance sheets also do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in coal prices. An increase of 10% in the spread of credit default swaps of our trading partners would result in an increase of $5 million in our credit reserve at December 31, 2011.

Once we have delivered a physical commodity or agreed to financial settlement terms, we are subject to collection risk. Collection risk is similar to credit risk and collection risk is accounted for when we establish our provision for uncollectible accounts. We manage this risk using the same techniques and processes used in credit risk discussed above.

We also monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. See note 4 to our consolidated financial statements.

GenOn Credit Risk

In valuing our derivative contract liabilities, we apply a valuation adjustment for our non-performance which is based on the probability of our default. Our methodology incorporates published spreads on our credit default swaps, where available, or proxies based upon published spreads. An increase of 10% in the spread of our credit default swap rate would have a $1 million effect on our consolidated statement of operations for 2011.

Broker Quotes

The fair value of our derivative contract assets and liabilities is based largely on observable quoted prices from exchanges and unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. We think that these prices represent the best available information for valuation purposes. In determining the fair value of our derivative contract assets and liabilities, we use third-party market pricing where available. Note 4 to our consolidated financial statements explains the fair value hierarchy. Our transactions in Level 1 of the fair value hierarchy primarily consist of natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. For these transactions, we use the unadjusted published settled prices on the valuation date. Our transactions in Level 2 of the fair value hierarchy primarily include non-exchange-traded derivatives such as OTC forwards, swaps and options, and certain energy derivative instruments that are cleared and settled through exchanges. We value these transactions using indicative quoted prices from independent brokers or other widely-accepted valuation methodologies. Transactions are classified in Level 2 if substantially all (greater than 90%) of the fair value can be corroborated using observable market inputs such as transactable broker quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. The quotes that we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes on the valuation date for each delivery location that extend for the tenor of our underlying contracts. The number of quotes that we can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, we use an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other

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external sources, we will assign the quote to a lower level within the fair value hierarchy. In some instances, we may combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the delivery location under the contract. We also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. We perform validation procedures on the broker quotes at least on a monthly basis. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may discard a broker quote if it is a clear outlier and multiple other quotes are obtained. At December 31, 2011, we obtained broker quotes for 100% of our delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. Our transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or we are only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, we may apply valuation techniques such as extrapolation and other quantitative methods to determine fair value. Proprietary models may also be used to determine the fair value of certain of our derivative contract assets and liabilities that may be structured or otherwise tailored. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At December 31, 2011, our assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 4% of our total assets and 11% of our total liabilities measured at fair value.

Value at Risk

Our risk management policy limits our trading to certain products and contains limits and restrictions related to our asset management, proprietary trading and fuel oil management activities.

We manage the price risk associated with asset management activities through a variety of methods. Our risk management policy requires that asset management activities are restricted to only those activities that are risk-reducing. We ensure compliance with this restriction through the use of a variety of internal controls, with the primary control being a test at the transactional level of each individual forward transaction executed relative to the overall asset position.

We also use VaR to measure the market price risk of our energy asset portfolio as a result of potential changes in market prices. VaR is a statistical model that provides an estimate of potential loss. We calculate VaR based on the parametric variance/covariance approach, utilizing a 95% confidence interval and a one-day holding period on a rolling 24-month forward looking period. Additionally, we estimate correlation based on historical commodity price changes. Volatilities are based on a combination of historical price changes and implied market rates.

VaR is calculated quarterly on an asset management portfolio comprised of mark-to-market and non mark-to-market energy assets and liabilities, including generating facilities and bilateral physical and financial transactions. Asset management VaR levels are substantially reduced as a result of our decision to actively hedge economically in the forward markets the commodity price risk related to the expected generation and fuel usage of our generating facilities. See Item 1, "Business Asset Management" for discussion of our hedging strategies.

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The following table summarizes year-end, average, high and low VaR for our asset management portfolio:

	2011	2010
	(in millions)	
Asset Management VaR		
Year-end	$ 18	$ 26
Average	$ 22	$ 11
High	$ 29	$ 26
Low	$ 18	$ 5

We calculate VaR daily on portfolios consisting of mark-to-market and non mark-to-market bilateral physical and financial transactions related to our proprietary trading activities and fuel oil management operations.

The following table summarizes year-end, average, high and low VaR for our proprietary trading and fuel oil management activities:

	2011	2010
	(in millions)	
Proprietary Trading and Fuel Oil Management VaR		
Year-end	$ 3	$ 2
Average	$ 2	$ 2
High	$ 4	$ 3
Low	$ 1	$ 1

Because of inherent limitations of statistical measures such as VaR and the seasonality of changes in market prices, the VaR calculation may not reflect the full extent of our commodity price risk exposure on our cash flows and liquidity. Additionally, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated VaR, and such changes could have a material effect on our financial results.

Interest Rate Risk

Fair Value Measurement

We are also subject to interest rate risk when discounting to account for time value in determining the fair value of our derivative contract assets and liabilities. The nominal value of our derivative contract assets and liabilities is discounted using a LIBOR forward interest rate curve based on the tenor of our transactions. It is estimated that a one percentage point change in market interest rates would result in a change of $16 million to our derivative contract assets and a change of $5 million to our derivative contract liabilities at December 31, 2011.

Debt

Some of our debt is subject to variable interest rates, including our $691 million senior secured term loan and our $788 million senior secured revolving credit facility. With the senior secured term loan fully drawn, it is estimated that a one percentage point change in market interest rates above 1.75% would result in a change in our annual interest expense of approximately $7 million. If the senior secured revolving credit facility was fully drawn, it is estimated that a one percentage point change in market interest rates would result in a change in our annual interest expense of approximately $8 million.

The GenOn Marsh Landing credit agreement is also subject to variable interest rates. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing's debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing's collateral requirements under its PPA with PG&E. The interest rate swaps cover 100% of the expected outstanding term loans balances during the operating period and a substantial portion of the expected outstanding term loans balances during the construction period. The remaining borrowings during the construction period are still subject to variability in interest rates. At the projected peak borrowing levels during the construction period, a one percentage point change in market interest rates would result in a change in our annual interest cost of less than $1 million.

Coal Agreement Risk

Our coal supply comes primarily from the Northern Appalachian and Central Appalachian coal regions. We enter into contracts of varying tenors to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2014 and one that extends to 2020. Excluding our Keystone and Conemaugh generating facilities (which are not 100% owned by us) and excluding our Seward generating facility (which burns waste coal supplied by an all-requirements contract), we had exposure to three counterparties at December 31, 2011 and 2010, that each represented an exposure of more than 10% of our total coal commitments, by volume, for the respective succeeding year, and in aggregate represented approximately 62% and 76% of our total coal commitments at December 31, 2011 and 2010, respectively. At December 31, 2011 and 2010, one counterparty represented an exposure of 38% and 52%, respectively, of these total coal commitments, by volume.

In addition, we have non-performance risk associated with our coal agreements. There is risk that our coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. If our coal suppliers do not perform in accordance with the agreements, we may have to procure coal in the market to meet our needs, or power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. We seek to mitigate this risk through diversification of coal suppliers, to the extent possible, and through guarantees. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers. Non-performance or default risk by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows. See note 4 to our consolidated financial statements.

Certain of our coal contracts are not required to be recorded at fair value under the accounting guidance for derivative financial instruments. As such, these contracts are not included in derivative contract assets and liabilities in the consolidated balance sheets. These contracts contain pricing terms that are favorable compared to forward market prices at December 31, 2011, and are projected to provide a $1 million benefit to our realized value of hedges through 2013 as the coal is utilized in the production of electricity.

Item 8. *Financial Statements and Supplementary Data*

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

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Item 9A. *Controls and Procedures*

Effectiveness of Disclosure Controls and Procedures

As required by Exchange Act Rule 13a-15(b), our management, including our Chief Executive Officer and our Chief Financial Officer, conducted an assessment of the effectiveness of the design and operation of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of December 31, 2011. Based upon this assessment, our management concluded that, as of December 31, 2011, the design and operation of these disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined by Rules 13a-15(f) under the Exchange Act). The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with United States generally accepted accounting principles. Internal control over financial reporting includes those processes and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- provide reasonable assurance that transactions are recorded properly to allow for the preparation of financial statements, in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company;

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements; and

- provide reasonable assurance as to the detection of fraud.

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we carried out an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011. In conducting our assessment, management utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*. Based on this assessment, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Our independent registered public accounting firm, KPMG LLP, has issued an attestation report on our internal control over financial reporting. KPMG LLP's report can be found on page F-1.

Changes in Internal Control over Financial Reporting

We have completed the execution of our merger integration activities and related internal controls over financial reporting as a result of the Merger. There have been no changes in our internal controls over financial reporting that have occurred during the quarter ended December 31, 2011 that have materially affected or are reasonably likely to materially affect the internal controls over financial reporting.

Item 9B. *Other Information.*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 11. *Executive Compensation.*

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The following table sets forth the compensation plans under which our equity securities were authorized for issuance at December 31, 2011:

Plant Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (in millions)	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities to be issued upon exercise of outstanding options, warrants and rights) (in millions)
Equity compensation plans approved by security holders	21(1)	$ 6.86	34
Equity compensation plans not approved by security holders			
Total	21	$ 6.89	34

(1) Includes 3 million shares issuable for outstanding performance-based restricted stock units assuming a performance multiplier of 200% of the targeted grant.

As of the date of the Merger, the GenOn Energy, Inc. 2010 Omnibus Incentive Plan became effective and permits the Company to grant various stock-based compensation awards to employees, consultants and directors. We terminated the GenOn Energy, Inc. 2002 Stock Plan, the GenOn Energy, Inc. 2002 Long-Term Incentive Plan, the Long-Term Incentive Plan of GenOn Energy, Inc., the GenOn Energy, Inc. Transition Stock Plan and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. Outstanding awards under the terminated plans remain subject to the terms and conditions of the applicable plans.

The GenOn Energy, Inc. 2010 Omnibus Incentive Plan provides for the granting of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards, other stock-based awards and non-employee director awards.

Other information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

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Item 13. ***Certain Relationships and Related Transactions and Director Independence.***

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services.***

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

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PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) 1. *Financial Statements*

2. *Financial Statement Schedules*

3. *Exhibits*

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
GenOn Energy, Inc.:

We have audited the accompanying consolidated balance sheets of GenOn Energy, Inc. and subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011. We also have audited the Company's internal control over financial reporting at December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting within Item 9A. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GenOn Energy, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

/s/ KPMG LLP

Houston, Texas
February 29, 2012

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	2011	2010	2009
	(in millions, except per share data)		
	(See notes 1 and 2 on the Merger)		
Operating revenues (including unrealized gains (losses) of $227, $45 and $(2), respectively)	$ 3,614	$ 2,270	$ 2,309
Cost of fuel, electricity and other products (including unrealized (gains) losses of $3, $87 and $(49), respectively)	1,610	963	710
Gross Margin (excluding depreciation and amortization)	2,004	1,307	1,599
Operating Expenses:			
Operations and maintenance	1,293	846	610
Depreciation and amortization	375	224	149
Impairment losses	133	565	221
Gain on sales of assets, net	(6)	(4)	(22)
Total operating expenses	1,795	1,631	958
Operating Income (Loss)	209	(324)	641
Other Income (Expense), net:			
Gain on bargain purchase, as retroactively amended		335	
Interest expense	(380)	(254)	(138)
Interest income	1	1	3
Other, net	(19)	7	(1)
Total other income (expense), net	(398)	89	(136)
Income (Loss) Before Income Taxes	(189)	(235)	505
Provision (benefit) for income taxes		(2)	12
Net Income (Loss)	$ (189)	$ (233)	$ 493
Basic and Diluted EPS:			
Basic EPS	$ (0.24)	$ (0.53)	$ 1.20
Diluted EPS	$ (0.24)	$ (0.53)	$ 1.20
Weighted average shares outstanding	772	441	411
Effect of dilutive securities			1
Weighted average shares outstanding assuming dilution	772	441	412

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in millions) (See notes 1 and 2 on the Merger)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,668	$ 2,402
Funds on deposit	422	1,834
Receivables, net	357	538
Derivative contract assets	999	1,420
Inventories	563	553
Prepaid rent and other expenses	167	155
Total current assets	4,176	6,902
Property, Plant and Equipment, net	6,191	6,229
Noncurrent Assets:		
Intangible assets, net	48	140
Derivative contract assets	733	716
Deferred income taxes	294	361
Prepaid rent	386	348
Other	441	503
Total noncurrent assets	1,902	2,068
Total Assets	$ 12,269	$ 15,199
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 10	$ 2,061
Accounts payable and accrued liabilities	790	903
Derivative contract liabilities	720	1,227
Deferred income taxes	294	361
Other	130	128
Total current liabilities	1,944	4,680
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,122	4,020
Derivative contract liabilities	131	189
Pension and postretirement obligations	259	171
Other	696	705
Total noncurrent liabilities	5,208	5,085
Commitments and Contingencies		
Stockholders' Equity:		

Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at December 31, 2011 and 2010		
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 771,692,734 shares and 770,857,530 shares at December 31, 2011 and 2010, respectively	1	1
Additional paid-in capital	7,449	7,432
Accumulated deficit	(2,163)	(1,974)
Accumulated other comprehensive loss	(170)	(25)
Total stockholders' equity	5,117	5,434
Total Liabilities and Stockholders' Equity	$ 12,269	$ 15,199

The accompanying notes are an integral part of these consolidated financial statements

GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
			(in millions)			
			(See notes 1 and 2 on the Merger)			
Balance, December 31, 2008	$	$ 6,074	$ (2,234)	$ (90)	$ 3,750	
Share repurchases		(4)			(4)	
Stock-based compensation expense		26			26	
Net income			493		493	$ 493
Pension and other postretirement benefits, net of tax of $0				37	37	37
Comprehensive income						$ 530
Balance, December 31, 2009		6,096	(1,741)	(53)	4,302	
Share repurchases		(11)			(11)	
Stock-based compensation expense		42			42	
Exercise of stock options		1			1	
Shares issued pursuant to the Merger of Mirant and RRI Energy	1	1,304			1,305	
Net loss			(233)		(233)	$ (233)
Pension and other postretirement benefits, net of tax of $0				6	6	6
Deferred gain from cash flow hedges-interest rate swaps, net of tax of $0				21	21	21
Change in fair value of available-for-sale securities, net of tax of $0				1	1	1
Comprehensive loss						$ (205)
Balance, December 31, 2010	1	7,432	(1,974)	(25)	5,434	
Stock-based compensation expense		14			14	
Exercise of stock options		3			3	
Net loss			(189)		(189)	(189)
Pension and other postretirement benefits, net of tax of $0				(89)	(89)	(89)
Deferred loss from cash flow hedges-interest rate swaps, net of tax of $0				(55)	(55)	(55)
Change in fair value of available-for-sale securities, net of tax of $0				(1)	(1)	(1)
Comprehensive loss						$ (334)
Balance, December 31, 2011	$ 1	$ 7,449	$ (2,163)	$ (170)	$ 5,117	

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2011	2010	2009
		(in millions) (See notes 1 and 2 on the Merger)	
Cash Flows from Operating Activities:			
Net income (loss)	$ (189)	$ (233)	$ 493
Adjustments to reconcile income (loss) and changes in operating assets and liabilities to net cash provided by operating activities:			
Depreciation and amortization	390	229	156
Impairment losses	133	565	221
Amortization of acquired contracts	(33)		
Gain on sales of assets, net	(6)	(4)	(22)
Net changes in derivative contracts	(224)	42	(47)
Stock-based compensation expense	14	41	24
Postretirement benefits curtailment gain		(37)	
Lower of cost or market inventory adjustments	13	22	32
Gain on bargain purchase, as retroactively amended		(335)	
Loss on early extinguishment of debt	23		
Potomac River settlement obligation		32	
Other, net	(5)	28	1
Changes in operating assets and liabilities, net of effects of the Merger:			
Receivables, net	204	(10)	348
Funds on deposit	17	(42)	21
Inventories	(21)	(65)	(35)
Other assets	(30)	(41)	(47)
Accounts payable and accrued liabilities	(47)	(3)	(334)
Other liabilities	26	10	2
Total adjustments	454	432	320
Net cash provided by operating activities of continuing operations	265	199	813
Net cash provided by operating activities of discontinued operations		6	9
Net cash provided by operating activities	265	205	822
Cash Flows from Investing Activities:			
Cash acquired from RRI Energy, Inc.		717	
Capital expenditures	(450)	(304)	(676)
Proceeds from the sales of assets	18	4	26
Capital contributions			(5)
Restricted funds on deposit, net	1,424	(1,545)	1
Other, net	(21)	(43)	3
Net cash provided by (used in) investing activities	971	(1,171)	(651)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	107	1,896	
Repayment of long-term debt	(2,078)	(379)	