GenOn Energy, Inc.
Form 10-Q
November 09, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2012

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)

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. x 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). x Yes o No

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 x	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 Exchange Act). o Yes x No

As of November 2, 2012, there were 772,935,824 shares of the registrant s Common Stock, $0.001 par value per share, outstanding.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Glossary of Certain Defined Terms

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, 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.
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.
CFTC	U.S. Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act.
CO_2	carbon dioxide.
CSAPR	Cross-State Air Pollution Rule.
dark spread	the difference between power prices and the cost to generate electricity with coal.
D.C. Circuit	the United States Court of Appeals for the District of Columbia Circuit.
deactivation	includes retirement, mothballing and long-term protective layup. In each instance, the deactivated unit cannot be currently called upon to generate electricity.
Dodd-Frank Act	the Dodd-Frank Wall Street Reform and Consumer Protection Act.
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.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
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 Mirant/RRI Merger.
GenOn Americas	GenOn Americas, Inc.

Table of Contents

GenOn Americas Generation	GenOn Americas Generation, LLC.
GenOn credit facilities	senior secured term loan and revolving credit facility of GenOn and certain of its subsidiaries.
GenOn Energy Holdings	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
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.
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.
ISO-NE	Independent System Operator-New England.
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. Although the units are not decommissioned and reactivation remains a technical possibility, we do not expect to make any further investment in environmental controls for the units. Further, reactivation after the long-term protective layup would likely involve numerous new permits and substantial additional investment.
MADEP	Massachusetts Department of Environmental Protection.
MC Asset Recovery	MC Asset Recovery, LLC.
MDE	Maryland Department of the Environment.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
Mirant/RRI Merger	the merger completed on December 3, 2010 pursuant to the Mirant/RRI Merger Agreement.
Mirant/RRI Merger Agreement	the agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant Debtors	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and certain of its subsidiaries.
MISO	Midwest Independent Transmission System Operator.
mothballed	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.
MPSC	Maryland Public Service Commission.

MW	megawatt.
MWh	megawatt hour.

Table of Contents

NAAQS	National Ambient Air Quality Standards.
NERC	North American Electric Reliability Corporation.
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.
NPDES	national pollutant discharge elimination system.
NRG	NRG Energy, Inc.
NRG Merger	the merger contemplated in the NRG Merger Agreement.
NRG Merger Agreement	the agreement by and among NRG Energy, Inc., Plus Merger Corporation and GenOn Energy, Inc. dated as of July 20, 2012.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
OCI	other comprehensive income.
OTC	over-the-counter.
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.
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.
PPA	power purchase agreement.
Protective Charter Amendment	the Certificate of Amendment to our Third Restated Certificate of Incorporation dated May 4, 2011.
REMA	GenOn REMA, LLC and its subsidiaries, which include three generating facilities under operating leases.
retirement	the unit has been removed from service and is unavailable for service and not expected to return to service in the future.
RMR	reliability-must-run.
ROC	Risk Oversight Committee.

RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Mirant/RRI Merger.
RTO	regional transmission organization.
scrubbers	flue gas desulfurization emissions controls.
Securities Act	Securities Act of 1933, as amended.
SO_2	sulfur dioxide.

Table of Contents

Southern Company	The Southern Company.
spark spread	the difference between power prices and the cost to generate electricity with natural gas.
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.
VaR	value at risk.
VIE	variable interest entity.

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this report 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 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;
- 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;

Table of Contents

- hazards customary to the power generation industry, including those listed in this cautionary statement and elsewhere in this report, 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;

- our ability to borrow additional funds and access capital markets; and

- the successful and timely completion of the proposed NRG Merger, which could be materially and adversely affected by, among other things, resolving any litigation brought in connection with the proposed NRG Merger, the timing and terms and conditions of required stockholder, governmental and regulatory approvals, and the ability to maintain relationships with employees, customers or suppliers as well as the ability to integrate the businesses and realize cost savings.

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 Management s Discussion and Analysis of Financial Condition and Results of Operations and the accompanying notes to GenOn s interim financial statements, other factors that could affect our future performance are set forth in our 2011 Annual Report on Form 10-K. 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.

Table of Contents

PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions, except per share data)			
Operating revenues (including unrealized gains (losses) of $(245), $49, $(204) and $(86), respectively)	$ 755	$ 1,080	$ 1,997	$ 2,706
Cost of fuel, electricity and other products (including unrealized (gains) losses of $(58), $11, $25 and $(27), respectively)	346	526	930	1,317
Gross Margin (excluding depreciation and amortization)	409	554	1,067	1,389
Operating Expenses:				
Operations and maintenance	268	286	840	963
Depreciation and amortization	91	96	269	272
Impairment losses	47	133	47	133
Gain on sales of assets, net	(1)	(6)	(9)	(5)
Total operating expenses	405	509	1,147	1,363
Operating Income (Loss)	4	45	(80)	26
Other Income (Expense), net:				
Interest expense	(86)	(86)	(260)	(291)
Interest income	1	1	1	1
Other, net		1	2	(21)
Total other expense, net	(85)	(84)	(257)	(311)
Loss Before Income Taxes	(81)	(39)	(337)	(285)
Provision for income taxes	4	1	8	4
Net Loss	$ (85)	$ (40)	$ (345)	$ (289)
Basic and Diluted EPS:				
Basic EPS	$ (0.11)	$ (0.05)	$ (0.45)	$ (0.37)
Diluted EPS	$ (0.11)	$ (0.05)	$ (0.45)	$ (0.37)
Weighted average shares outstanding	774	772	774	771
Effect of dilutive securities				
Weighted average shares outstanding assuming dilution	774	772	774	771

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

1

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS (UNAUDITED)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
		(in millions)		
Net Loss	$ (85)	$ (40)	$ (345)	$ (289)
Other Comprehensive Income (Loss), net of tax of $0:				
Unrealized losses:				
Cash flow hedges interest rate swaps	(5)	(39)	(17)	(50)
Available-for-sale securities				(1)
Pension and other postretirement benefits actuarial losses, net	(9)		(9)	
Reclassifications to net loss:				
Cash flow hedges interest rate swaps	(1)		(1)	
Pension and other postretirement benefits actuarial losses, net	2	1	6	3
Pension and other postretirement benefits prior service credit, net		(1)	(2)	(3)
Other, net			1	
Other Comprehensive Loss	(13)	(39)	(22)	(51)
Comprehensive Loss	$ (98)	$ (79)	$ (367)	$ (340)

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2012	December 31, 2011
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,855	$ 1,668
Funds on deposit	261	422
Receivables, net	294	357
Derivative contract assets	636	999
Inventories	447	563
Prepaid rent and other expenses	182	167
Total current assets	3,675	4,176
Property, plant and equipment, gross	7,616	7,351
Accumulated depreciation and amortization	(1,351)	(1,160)
Property, Plant and Equipment, net	6,265	6,191
Noncurrent Assets:		
Intangible assets, net	44	48
Derivative contract assets	588	733
Deferred income taxes	196	294
Prepaid rent	413	386
Other	394	441
Total noncurrent assets	1,635	1,902
Total Assets	$ 11,575	$ 12,269
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 10	$ 10
Accounts payable and accrued liabilities	690	790
Derivative contract liabilities	398	720
Deferred income taxes	196	294
Other	105	130
Total current liabilities	1,399	1,944
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,361	4,122
Derivative contract liabilities	184	131
Pension and postretirement obligations	252	259
Other	617	696
Total noncurrent liabilities	5,414	5,208
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at September 30, 2012 and December 31, 2011		
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 772,922,439 shares and 771,692,734 shares at September 30, 2012 and December 31, 2011, respectively	1	1
Additional paid-in capital	7,461	7,449
Accumulated deficit	(2,508)	(2,163)
Accumulated other comprehensive loss	(192)	(170)
Total stockholders equity	4,762	5,117
Total Liabilities and Stockholders Equity	$ 11,575	$ 12,269

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions)	
Cash Flows from Operating Activities:		
Net loss	$ (345)	$ (289)
Adjustments to reconcile net loss and changes in operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	269	272
Impairment losses	47	133
Amortization of acquired contracts	(36)	(25)
Gain on sales of assets, net	(9)	(5)
Unrealized losses	229	59
Stock-based compensation expense	15	11
Excess materials and supplies inventory reserve	35	
Lower of cost or market inventory adjustments	82	2
Loss on early extinguishment of debt		23
Advance settlement of out-of-market contract obligation	(20)	
Reversal of Potomac River settlement obligation	(31)	
Large scale remediation and settlement costs	(3)	30
Other, net	13	10
Changes in operating assets and liabilities	20	61
Total adjustments	611	571
Net cash provided by operating activities	266	282
Cash Flows from Investing Activities:		
Capital expenditures	(486)	(328)
Proceeds from the sales of assets	14	18
Restricted funds on deposit and other, net	158	1,396
Net cash provided by (used in) investing activities	(314)	1,086
Cash Flows from Financing Activities:		
Proceeds from long-term debt	243	50
Repayment of long-term debt	(8)	(2,075)
Other, net		1
Net cash provided by (used in) financing activities	235	(2,024)
Net Increase (Decrease) in Cash and Cash Equivalents	187	(656)
Cash and Cash Equivalents, beginning of period	1,668	2,402
Cash and Cash Equivalents, end of period	$ 1,855	$ 1,746
Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	$ 174	$ 225
Cash paid for income taxes (net of refunds received)	$ 12	$ (6)

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Description of Business and Accounting and Reporting Policies

Background

We are a wholesale generator with approximately 22,000 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. See note 2 for a discussion of generating facilities in the Eastern PJM, Western PJM/MISO and California segments that have units we deactivated in 2012 or expect to deactivate in 2013 and 2015.

We were formed as a Delaware corporation in August 2000. We, us, our and GenOn refer to GenOn Energy, Inc. and, except where the contex indicates otherwise, its subsidiaries, after giving effect to the Mirant/RRI Merger.

Proposed Merger with NRG

On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. Upon the terms and subject to the conditions set forth in the NRG Merger Agreement, which has been approved by the boards of directors of GenOn and NRG, a wholly-owned subsidiary of NRG will merge with and into GenOn, with GenOn continuing as the surviving corporation and a wholly owned subsidiary of NRG.

Upon closing of the NRG Merger, each issued and outstanding share of our common stock will automatically convert into the right to receive 0.1216 shares of common stock of NRG based on the exchange ratio. All outstanding stock options (other than options granted in 2012) will immediately vest and all outstanding stock options will generally convert upon completion of the NRG Merger into stock options with respect to NRG common stock, after giving effect to the exchange ratio. In addition, all outstanding restricted stock units (other than restricted stock units granted in 2012) will immediately vest and all outstanding restricted stock units will be exchanged for the NRG Merger consideration. All outstanding stock options and restricted stock units granted in 2012 will vest at the holder s termination date if the termination is as a result of the NRG Merger and within two years of the closing date. See note 7.

The NRG Merger is intended to qualify as a tax-free reorganization under the IRC, as amended, so that none of GenOn, NRG or any of our stockholders generally will recognize any gain or loss in the transaction, except with respect to cash received in lieu of fractional shares of NRG common stock.

Completion of the NRG Merger is contingent upon, among other things, (a) approvals by NRG stockholders of the issuance of NRG common stock in the NRG Merger and the approval and adoption of the amendment to NRG s certificate of incorporation to allow the size of NRG s board of directors to be increased to 16 in connection with the closing of the NRG Merger at a meeting to be held on November 9, 2012, (b) adoption of the NRG Merger Agreement by our stockholders at a meeting to be held on November 9, 2012, (c) effectiveness of an NRG registration statement on Form S-4, which occurred on October 5, 2012, and approval of the New York Stock Exchange listing for the NRG common stock to be issued in the NRG Merger, (d) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, which occurred on September 21, 2012, and (e) receipt of all required regulatory approvals, including approvals from the Public Utility Commission of Texas, which occurred on October 25, 2012, the FERC and the New York Public Service Commission.

We and NRG are also subject to restrictions on our respective ability to solicit alternative acquisition proposals and to provide information to, and engage in discussion with, third parties, except under limited circumstances to permit our or NRG s board of directors to comply with their respective fiduciary duties. The NRG Merger Agreement contains termination rights for both us and NRG and further provides that, upon termination of the NRG Merger Agreement under specified circumstances, NRG may be required to pay a termination fee of $120 million to us and we may be required to pay NRG a termination fee of $60 million.

Table of Contents

In addition, at NRG s request and upon the terms and subject to the conditions of the NRG Merger Agreement, we will commence a change of control tender offer for each series of our outstanding notes due 2014, 2017, 2018 and 2020, conditioned on the completion of the NRG Merger (the Change in Control Offers). In addition, upon the terms and subject to the conditions of the NRG Merger Agreement, NRG may, at its election following consultation with us, commence a tender offer for cash or an exchange offer for securities for all or any portion of our outstanding notes due 2014, 2017, 2018 and 2020, conditioned on the completion of the NRG Merger (together with the Change in Control Offers, the Debt Offers). NRG may, upon the terms and subject to the conditions of the NRG Merger Agreement, elect to also undertake a consent solicitation to alter the terms of any of our remaining notes due 2014, 2017, 2018 and 2020 outstanding after such tender or exchange offers. NRG intends to fund the Debt Offers and the related fees, commissions and expenses with a combination of funds available at each company (including funds available under existing credit facilities) and, to the extent necessary, new financing for which NRG obtained commitment letters from Credit Suisse Securities (USA) LLC and Morgan Stanley Senior Funding, Inc. to fund up to $1.6 billion under a new senior secured term loan facility, to the extent such funds are necessary to consummate the Debt Offers. On October 19, 2012, NRG elected to amend the commitment letters to permanently reduce the aggregate commitment amount to $1.0 billion and NRG indicated its intent to fund additional requirements, if any, from its available liquidity including cash on hand and credit facilities. NRG has agreed to use reasonable best efforts to obtain the financing, to the extent required, and we have agreed to use reasonable best efforts to cooperate in NRG s efforts to obtain the financing. There are no financing conditions to the NRG Merger and the NRG Merger is not conditioned upon the completion of the Debt Offers or the funding of the financing.

In addition, we will experience an ownership change under the applicable tax rules as a result of the NRG Merger. Immediately following the NRG Merger, we and NRG will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct the pre-NRG Merger NOL carry forwards of GenOn against the post-merger taxable income of the group will be substantially limited as a result of the ownership change.

We anticipate completing the NRG Merger by the first quarter of 2013. Prior to the completion of the NRG Merger, we and NRG will continue to operate as independent companies. Except for specific references to the pending NRG Merger, the disclosures contained in this report on Form 10-Q relate solely to us. Information concerning the proposed NRG Merger is included in a joint proxy statement/prospectus contained in the registration statement on Form S-4, which NRG filed with the Securities and Exchange Commission in connection with the NRG Merger on October 5, 2012.

Basis of Presentation

The consolidated interim financial statements and notes (interim financial statements) are unaudited, omit certain disclosures and should be read in conjunction with our audited consolidated financial statements and notes in our 2011 Annual Report on Form 10-K. These interim financial statements have been prepared in accordance with GAAP from records maintained by us. All significant intercompany accounts and transactions have been eliminated in consolidation. The interim financial statements reflect all normal recurring adjustments necessary, in management s opinion, to present fairly our financial position and results of operations for the reported periods. Amounts reported for interim periods may not be indicative of a full year period because of seasonal fluctuations in demand for electricity and energy services, changes in commodity prices, and changes in regulations, timing of maintenance and other expenditures, dispositions, changes in interest expense and other factors.

At September 30, 2012 and December 31, 2011, substantially all of our subsidiaries are wholly-owned and located in the United States. We do not consolidate five power generating facilities, which are under operating leases; a 50% equity investment in a cogeneration facility; and a VIE (MC Asset Recovery) for which we are not the primary beneficiary. See note 11 for further discussion of MC Asset Recovery.

The preparation of interim financial statements in conformity with GAAP requires management to make various estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent

Table of Contents

assets and liabilities at the date of the interim financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. Our significant estimates include:

- estimating the fair value of certain derivative contracts;
- estimating the inventory reserve;
- estimating future taxable income in evaluating the deferred tax asset valuation allowance;
- estimating the useful lives of long-lived assets;
- estimating future costs and the valuation of asset retirement obligations;
- estimating future cash flows in determining impairments of long-lived assets and definite-lived intangible assets;
- estimating the fair value and expected return on plan assets, discount rates and other actuarial assumptions used in estimating pension and other postretirement benefit plan liabilities; and
- estimating losses to be recorded for contingent liabilities.

We evaluate events that occur after the balance sheet date but before the financial statements are issued for potential recognition or disclosure. Based on the evaluation, we determined that there were no material subsequent events for recognition or disclosure other than those disclosed herein.

Our results of operations for the three and nine months ended September 30, 2011 have been retroactively amended for the revisions to the provisional purchase price allocation in connection with the Mirant/RRI Merger.

We had disclosed in our 2011 Annual Report on Form 10-K that it was possible that RRI Energy had experienced an ownership change under the applicable tax rules as a result of the Mirant/RRI Merger. Based on further inquiries, we do not think that RRI Energy experienced an ownership change as a result of the Mirant/RRI Merger or following the Mirant/RRI Merger through December 31, 2011.

Table of Contents

Funds on Deposit

Funds on deposit are included in current and noncurrent assets in the consolidated balance sheets. Funds on deposit include the following:

		September 30, 2012		December 31, 2011
		(in millions)		
Cash collateral posted energy trading and marketing	$	150	$	185
Cash collateral posted other operating activities(1)		59		39
Cash collateral posted surety bonds(2)		34		34
GenOn Marsh Landing development project cash collateral posted(3)		80		131
Environmental compliance deposits(4)		35		34
GenOn Mid-Atlantic restricted cash(5)				166
Other		36		16
Total current and noncurrent funds on deposit		394		605
Less: Current funds on deposit		261		422
Total noncurrent funds on deposit	$	133	$	183

(1) Includes $32 million related to the Potomac River obligation under the 2008 agreement with the City of Alexandria, which were returned to us in October 2012. See note 2.

(2) Represents cash under surety bonds posted primarily with the PADEP related to environmental obligations.

(3) Represents cash-collateralized letters of credit to support the Marsh Landing development project.

(4) Represents deposits with the State of Pennsylvania to guarantee our obligations related to future closures of coal ash landfill sites and with the State of New Jersey to satisfy our obligations to remediate site contamination. See note 11.

(5) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation, which was settled in June 2012. See note 11.

Inventories

Inventories were comprised of the following:

	September 30, 2012	December 31, 2011
	(in millions)	
Fuel inventory:		

Coal	$	153	$	229
Fuel oil		87		108
Natural gas				1
Other		3		5
Materials and supplies(1)		169		201
Purchased emissions allowances		35		19
Total inventories	$	447	$	563

(1) Amount is net of an inventory reserve of $35 million and $0 at September 30, 2012 and December 31, 2011, respectively. See note 2.

During the three months ended September 30, 2012 and 2011, we recorded $17 million and $1 million, respectively, and during the nine months ended September 30, 2012 and 2011, we recorded $82 million and $2 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

Table of Contents

Capitalization of Interest Cost

We incurred the following interest costs:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions)			
Total interest costs	$ 96	$ 91	$ 286	$ 301
Capitalized and included in property, plant and equipment, net	(10)	(5)	(26)	(10)
Interest expense	$ 86	$ 86	$ 260	$ 291

The amounts of capitalized interest above include interest accrued. During the three months ended September 30, 2012 and 2011, cash paid for interest was $17 million and $16 million, respectively, of which $8 million and $4 million, respectively, were capitalized. During the nine months ended September 30, 2012 and 2011, cash paid for interest was $197 million and $234 million, respectively, of which $23 million and $9 million, respectively, were capitalized.

Guarantees and Indemnifications

We generally conduct business through various operating subsidiaries which enter into contracts as part of their business activities. In certain instances, the contractual obligations of such subsidiaries are guaranteed by, or otherwise supported by, us or another of our subsidiaries, including by letters of credit issued under the GenOn credit facilities. See note 5.

In addition, we, including our subsidiaries, enter into various contracts that include indemnification and guarantee provisions. Examples of these contracts include financing and lease arrangements, purchase and sale agreements, agreements to purchase or sell commodities, construction agreements and agreements with vendors. Although the primary obligation under such contracts is to pay money or render performance, such contracts may include obligations to indemnify the counterparty for damages arising from the breach thereof and, in certain instances, other existing or potential liabilities. In many cases, our maximum potential liability cannot be estimated because some of the underlying agreements contain no limits on potential liability.

We have guaranteed some non-qualified benefits of CenterPoint s existing retirees at September 20, 2002. The estimated maximum potential amount of future payments under the guarantee is $54 million at September 30, 2012 and $3 million is recorded in the consolidated balance sheet for this item.

Recently Adopted Accounting Guidance

Fair Value Measurement and Disclosure. We adopted FASB accounting guidance for the first quarter of 2012 that requires disclosure of the following:

- quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy;
- for those fair value measurements categorized within Level 3 of the fair value hierarchy, both the valuation processes used and the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any; and
- the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

See note 4 for these additional disclosures.

Table of Contents

Comprehensive Income. We adopted FASB accounting guidance for the first quarter of 2012 that requires companies to report the components of comprehensive income in either (a) a continuous statement of comprehensive income or (b) two separate but consecutive statements. The guidance does not change the items that must be reported in comprehensive income. See the consolidated statements of comprehensive loss and note 9.

New Accounting Guidance Not Yet Adopted at September 30, 2012

Balance Sheet Offsetting. In December 2011, the FASB issued updated guidance to provide enhanced disclosures such that users of the financial statements will be able to better evaluate the effect or potential effect of netting arrangements in the balance sheet. The guidance requires improved information about financial instruments and derivative instruments that are either offset according to specific guidance or subject to an enforceable master netting agreement or similar arrangement. The disclosures will provide both net and gross information for these assets and liabilities. Although we do not currently elect to offset assets and liabilities within the scope of the guidance, expanded disclosures will be required starting for the first quarter of 2013, along with retrospective presentation of prior periods.

2. Retirements, Mothballing or Long-Term Protective Layup of Generating Facilities

Facilities Announced in 2012

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 deactivated the following coal-fired units at the referenced times: Niles unit 2 (108 MW) June 2012, Niles unit 1 (109 MW) October 2012, Elrama units 1-3 (289 MW) mothballed June 2012 (plan to retire in March 2014) and Elrama unit 4 (171 MW) mothballed October 2012 (plan to retire in March 2014). We expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Portland (401 MW) January 2015, Gilbert unit 8 (90 MW) January 2015, Avon Lake (732 MW) April 2015, New Castle (330 MW) April 2015, Titus (243 MW) April 2015, Shawville (597 MW) place in long-term protective layup in April 2015 and Glen Gardner (160 MW) May 2015. We filed for RMR arrangements for Niles unit 1 and Elrama unit 4 that were in effect from June 1 through September 30, 2012. These RMR arrangements are subject to final FERC rulings.

Potomac River Generating Facility

During 2011, we entered into an agreement with the City of Alexandria, Virginia to remove permanently from service our 482 MW Potomac River generating facility. The agreement, which amends our Project Schedule and Agreement, dated July 2008 with the City of Alexandria, provides for the retirement of the Potomac River generating facility on October 1, 2012, subject to the determination of PJM that the retirement of the facility will not affect reliability and the consent of PEPCO. PJM made the necessary determination and in June 2012 PEPCO gave its consent. As a result, the Potomac River generating facility was retired in October 2012. Upon retirement of the Potomac River generating facility, all funds in the escrow account ($32 million) established under the July 2008 agreement were distributed to us in October 2012. We therefore reversed $31 million and $1 million of the previously recorded obligation under the 2008 agreement with the City of Alexandria as a reduction in operations and maintenance expense during the second and fourth quarters of 2012, respectively.

Contra Costa Generating Facility

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.

Table of Contents

Expenses, Property, Plant and Equipment, and Materials and Supplies Inventory Related to Deactivations

In connection with our decision to deactivate the generating facilities, we evaluated our materials and supplies inventory and determined that we have excess inventory. We established a reserve of $35 million (or $(0.04) per basic share) recorded to operations and maintenance expense during the first quarter of 2012 relating to our excess inventory. We will continue to monitor the inventory balances and could make changes to the reserve in the future. At September 30, 2012, the aggregate carrying value of property, plant and equipment, net and materials and supplies inventory, net for the generating facilities with an aggregate of 4,386 MW which we announced would be deactivated between 2012 and 2015 was $129 million and $25 million, respectively. In addition to the excess materials and supplies inventory reserve recorded in the first quarter, we incurred $8 million and $11 million during the three and nine months ended September 30, 2012, respectively for costs to deactivate generating facilities, which is included in operations and maintenance expense. We expect to incur additional costs in the future in connection with the deactivations, such as severance and other plant shutdown costs.

If market conditions and/or environmental and regulatory factors or assumptions change in the future, forecasted returns on investments necessary to comply with environmental regulations could change resulting in possible incremental investments if returns improve or deactivation of additional generating units or facilities if returns deteriorate. Such deactivations could result in additional charges, including impairments, severance costs and other plant shutdown costs.

3. Long-Lived Assets Impairments

Background

On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. We viewed the execution of the NRG Merger Agreement as a triggering event under accounting guidance and evaluated our long-lived assets for impairment.

For purposes of impairment testing, a long-lived asset must be grouped at the lowest level of identifiable cash flows. Each of our generating facilities is viewed as an individual asset group. Upon completion of the assessment, we determined that the Portland and Titus generating facilities were impaired at September 30, 2012, as the carrying values exceeded the undiscounted cash flows.

Table of Contents

Assumptions and Results

Our review of the long-lived assets included assumptions about the following: (a) electricity, fuel and emissions prices, (b) capacity prices, (c) impact of environmental regulations, including costs of CO_2 allowances under a potential cap-and-trade program, (d) timing and extent of generating capacity additions and retirements and (e) future capital expenditure requirements related to the generating facilities.

Our assumptions related to future prices of electricity, fuel, emissions allowances, and capacity were based on observable market prices to the extent available. Longer term power and capacity prices were derived from proprietary fundamental market modeling and analysis. The long-term capacity prices were based on estimated revenue requirements to incentivize new generation when needed to maintain reliability standards. For markets with established capacity markets, such as PJM, these estimates are generally consistent with the current structures. The assumptions regarding electricity demand were based on forecasts available from each ISO or NERC region, as applicable. Assumptions for generating capacity additions and retirements included publicly available announcements, which take into account renewable sources of electricity, as well as the need for capacity to maintain reliability in the longer term. In addition, we previously announced our plans for deactivation of the Portland and Titus generating facilities. See note 2.

We recorded impairment losses of $37 million and $10 million during the three months ended September 30, 2012 in the consolidated statement of operations to reduce the carrying values of the Portland and Titus generating facilities, respectively, to their estimated fair values.

The following table sets forth by level within the fair value hierarchy our assets that were accounted for at fair value on a non-recurring basis. All of our assets that were measured at fair value as a result of impairment losses recorded during the current period were categorized in Level 3 at September 30, 2012:

	Fair Value at September 30, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total	Loss Included in Earnings
			(in millions)		
Portland	$	$	$ 17	$ 17	$ 37
Titus			15	15	10
Total	$	$	$ 32	$ 32	$ 47

4. Financial Instruments

Derivatives and Hedging Activities

In connection with the 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 fuel inventories. 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 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 physical fuel oil inventories, optimize the approximately two million barrels of storage capacity that we own, and attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. The open positions in our trading activities comprising proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

Table of Contents

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that qualify for and for which we have elected the normal purchase or normal sale exceptions, which are not reflected in the consolidated balance sheet or results of operations prior to accrual of the settlement. We present our derivative contract assets and liabilities on a gross basis (regardless of master netting arrangements with the same counterparty). Cash collateral amounts are also presented on a gross basis.

During the second quarter of 2012, we could no longer assert that physical delivery was probable for the remaining coal agreements for which we had elected the normal purchase exception. As such, the normal purchase exception was removed, and we are required to apply fair value accounting to these contracts in the current period and prospectively.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge. In 2010, GenOn Marsh Landing entered into interest rate protection agreements (interest rate swaps) in connection with its project financing, which have been designated as cash flow hedges. GenOn Marsh Landing entered into the interest rate swaps to reduce the risks with respect to the variability of the interest rates for the term loan. With the exception of these interest rate swaps, we did not have any other derivative financial instruments designated as fair value or cash flow hedges for accounting purposes during the nine months ended September 30, 2012 or 2011.

The changes in fair value of cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts are, or have been, effective as hedges, until the forecasted transactions affect earnings. We record immediately into earnings the ineffective portion of changes in fair value of cash flow hedges.

Derivative financial instruments designated as cash flow hedges must have a high correlation between price movements in the derivative and the hedged item. If and when an acceptable level of correlation no longer exists, hedge accounting ceases and changes in fair value are recognized in our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the related deferred gains or losses in our results of operations. Changes in fair value of the associated hedging instrument are then recognized immediately in earnings for the remainder of the contract term unless a new hedging relationship is designated.

For our derivative financial instruments that have not been designated as cash flow hedges for accounting purposes, changes in such instruments fair values are recognized currently in earnings. Our derivative financial instruments are categorized based on the business objective the instrument is expected to achieve: asset management or trading, which includes proprietary trading and fuel oil management. For asset management activities, changes in fair value and settlement of derivative financial instruments used to hedge electricity economically are reflected in operating revenue and changes in fair value and settlement of derivative financial instruments used to hedge fuel economically 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.

We also consider risks associated with interest rates, counterparty credit and our own non-performance risk when valuing derivative financial instruments. The nominal value of the derivative contract assets and liabilities is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the transactions being valued.

Table of Contents

The following table presents the fair value of derivative financial instruments:

	Derivative Contract Assets Current	Derivative Contract Assets Long-Term	Derivative Contract Liabilities Current	Derivative Contract Liabilities Long-Term	Net Derivative Contract Assets (Liabilities)
			(in millions)		
September 30, 2012					
Commodity Contracts:					
Asset management	$ 462	$ 579	$ (222)	$ (129)	$ 690
Trading activities	174	9	(170)	(11)	2
Total commodity contracts	636	588	(392)	(140)	692
Interest Rate Contracts			(6)	(44)	(50)
Total derivatives	$ 636	$ 588	$ (398)	$ (184)	$ 642
December 31, 2011					
Commodity Contracts:					
Asset management	$ 538	$ 730	$ (255)	$ (97)	$ 916
Trading activities	461	3	(464)	(3)	(3)
Total commodity contracts	999	733	(719)	(100)	913
Interest Rate Contracts			(1)	(31)	(32)
Total derivatives	$ 999	$ 733	$ (720)	$ (131)	$ 881

The following table presents the net gains (losses) for derivative financial instruments recognized in income in the consolidated statements of operations:

	Three Months Ended September 30,			
	2012		2011	
Derivatives Not Designated as Hedging Instruments	Operating Revenues	Cost of Fuel, Electricity and Other Products	Operating Revenues	Cost of Fuel, Electricity and Other Products
		(in millions)		
Asset Management Commodity Contracts:				
Unrealized	$ (242)	$ 58	$ 38	$ (11)
Realized(1)(2)	102	(14)	54	(27)
Total asset management	$ (140)	$ 44	$ 92	$ (38)
Trading Commodity Contracts:				
Unrealized	$ (3)	$	$ 11	$
Realized(1)(2)	8		(13)	
Total trading	$ 5	$	$ (2)	$
Total derivatives	$ (135)	$ 44	$ 90	$ (38)

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(1) Represents the total cash settlements of derivative financial instruments during each reporting period (composed of the sum of the quarterly settlements) that existed at the beginning of each respective period.

(2) Excludes settlement value of fuel contracts classified as inventory.

Table of Contents

	Nine Months Ended September 30,			
	2012		2011	
Derivatives Not Designated as Hedging Instruments	**Operating Revenues**	**Cost of Fuel, Electricity and Other Products**	**Operating Revenues**	**Cost of Fuel, Electricity and Other Products**
	(in millions)			
Asset Management Commodity Contracts:				
Unrealized	$ (205)	$ (25)	$ (85)	$ 27
Realized(1)(2)	428	(42)	194	(84)
Total asset management	$ 223	$ (67)	$ 109	$ (57)
Trading Commodity Contracts:				
Unrealized	$ 1	$	$ (1)	$
Realized(1)(2)	3		(8)	
Total trading	$ 4	$	$ (9)	$
Total derivatives	$ 227	$ (67)	$ 100	$ (57)

(1) Represents the total cash settlements of derivative financial instruments during each reporting period (composed of the sum of the quarterly settlements) that existed at the beginning of each respective period.

(2) Excludes settlement value of fuel contracts classified as inventory.

The following table presents the losses on the interest rate swaps designated as cash flow hedges in the consolidated statements of operations and comprehensive income/loss:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Recognized in earnings on derivatives(1)(2)	$	$	$	$
Valuation adjustments(3)		4		4

(1) Represents the ineffective portion of the interest rate swaps classified as cash flow hedges and recorded in interest expense.

(2) All of the forecasted transactions (future interest payments) were deemed probable of occurring; therefore, no cash flow hedges were discontinued and no amount was recognized in our results of operations as a result of discontinued cash flow hedges.

(3) Represents the default risk of the counterparties to these transactions and our own non-performance risk. The effect of these valuation adjustments is recorded in interest expense.

At September 30, 2012, the maximum length of time we are hedging our exposure to the variability in future cash flows that may result from changes in interest rates is 11 years. Because a significant portion of the interest expense incurred by GenOn Marsh Landing during construction will be capitalized, amounts included in accumulated other comprehensive loss associated with construction period interest payments will be reclassified to property, plant and equipment and depreciated over the expected useful life of the Marsh Landing generating facility once it commences commercial operations in mid-2013. Actual amounts reclassified into earnings could vary from the amounts currently recorded as a result of future changes in interest rates. See note 9 for the effect of the cash flow hedges in comprehensive income/loss.

Table of Contents

The following tables present the notional quantity on long (short) positions for derivative financial instruments:

	Notional Volumes at September 30, 2012		
Derivative Instruments	**Derivative Contract Assets**	**Derivative Contract Liabilities** (in millions)	**Net Derivative Contracts**
Commodity Contracts (in equivalent MWh):			
Power(1)	(16)	(53)	(69)
Natural gas	2	(2)	
Coal	(1)	18	17
Interest Rate Contracts (in dollars)(2)		475	475

(1) Includes MWh equivalent of natural gas transactions used to hedge power economically.

(2) Beginning in mid-2013, the notional amount will increase to $500 million.

	Notional Volumes at December 31, 2011		
Derivative Instruments	**Derivative Contract Assets**	**Derivative Contract Liabilities** (in millions)	**Net Derivative Contracts**
Commodity Contracts (in equivalent MWh):			
Power(1)	(130)	73	(57)
Natural gas	(8)	10	2
Coal	3	12	15
Interest Rate Contracts (in dollars)(2)		475	475

(1) Includes MWh equivalent of natural gas transactions used to hedge power economically.

(2) Beginning in mid-2013, the notional amount will increase to $500 million.

Fair Value Measurements

Fair Value Hierarchy and Valuation Techniques. We apply recurring fair value measurements to our financial assets and liabilities. In estimating 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 instruments to price curves that cannot be validated through external pricing sources. Based on the observability of the inputs used in the valuation techniques, the financial assets and liabilities carried at fair value in the financial statements are classified as follows:

Level 1: Represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. Interest bearing funds and trading securities are also valued using Level 1 inputs.

Level 2: Represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category primarily includes non-exchange traded derivatives such as OTC forwards, swaps and options, and certain energy derivative instruments that are cleared and settled through exchanges. This category also includes interest rate swaps.

Level 3: Represents commodity derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from market sources (such as implied volatilities and correlations). The OTC, complex or structured derivative instruments that are transacted in less liquid markets with limited pricing information are included in Level 3. Examples are coal contracts, power transmission congestion products, less liquid power and natural gas contracts, and options valued using internally developed inputs.

Table of Contents

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls must be determined based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

A significant amount of the fair value of our derivative contract assets and liabilities is based on observable quoted prices from exchanges and indicative quoted prices from independent brokers in active markets that 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 derivative contract assets and liabilities, we use third-party market pricing where available. For transactions classified in Level 1 of the fair value hierarchy, we use the unadjusted published settled prices on the valuation date. For transactions classified in Level 2 of the fair value hierarchy, 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 assets and ask prices for liabilities. The quotes 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 as of the valuation date that extend for the tenor of the underlying contracts for each delivery location. 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 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 monthly. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may exclude from consideration a broker quote if it is a clear outlier and other quotes are obtained. At September 30, 2012, 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. Our techniques for fair value estimation include assumptions for market prices, including market price volatility and the volatility of the spread between multiple market prices. Proprietary models may also be used to estimate the fair value of derivative contract assets and liabilities that may be structured or otherwise tailored. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At September 30, 2012, the assets and liabilities classified as Level 3 in the fair value hierarchy represented 3% of total derivative contract assets and 22% of total derivative contract liabilities.

The fair value of our derivative contract assets and liabilities is also affected by assumptions as to time value, credit risk and non-performance risk. The nominal value of derivatives is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the transaction. Derivative contract assets are reduced to reflect the estimated default risk of counterparties on their contractual obligations. The counterparty default risk for our overall net position is measured based on published spreads on credit default swaps for counterparties, where available, or proxies based upon published spreads, applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. The fair value of derivative contract liabilities is reduced to reflect the estimated risk of default on contractual obligations to counterparties and is measured based on

Table of Contents

published default rates of our debt, where available, or proxies based upon published spreads. Credit risk and non-performance risk 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.

Information about Sensitivity to Changes in Significant Unobservable Inputs. The significant unobservable inputs used in the fair value measure of our commodity instruments categorized within Level 3 of the fair value hierarchy are estimates of future market volatility, estimates of forward congestion power price spreads and estimates of counterparty credit risk and our own non-performance risk. These assumptions are generally independent of each other. Volatility curves and power prices spreads are generally based on observable markets where available, or derived from historical prices and forward market prices from similar observable markets when not available. Increases in the price or volatility of the spread on a long position would result in a higher fair value measurement. Increases in the price or volatility of the spread on a short position would result in a lower fair value measurement. A change in the assumption used for the probability of default is accompanied by a directionally similar change in the adjustment to reflect the estimated default risk of counterparties on their contractual obligations, or the estimated risk of default on our own contractual obligations to counterparties.

Risk Management. The Risk and Finance Oversight Committee of the Board of Directors is responsible for oversight of the risk management of our commercial activities and enterprise risk management. In order to ensure proper daily oversight of our commercial risk controls, the Risk and Finance Oversight Committee has established the ROC with membership determined by the Chief Executive Officer. The ROC is responsible for ensuring that the necessary policies, procedures and systems are in place to measure, monitor and report on the risks associated with our commercial activities. The ROC is also responsible for safeguarding proprietary models against the negative impact of inadequate model control by providing oversight and control to model development, back-testing and verification, automation, security and revision control. The ROC must approve new valuation models or fundamental modifications to existing models. Model forecasts are back-tested annually and the results reviewed with the ROC.

Comprehensive, accurate and timely reporting and monitoring is essential to effectively manage market, credit and operational risks and to protect against large unanticipated losses. Management has established reporting and monitoring functions, which include daily and weekly reporting, to inform the ROC and Chief Risk Officer of its activities. The chair of the ROC reports to the Risk and Finance Oversight Committee on a quarterly basis, or more frequently, if events and circumstances dictate.

Table of Contents

Fair Value of Derivative Instruments and Certain Other Assets. The fair value measurements of financial assets and liabilities by class are as follows:

	September 30, 2012			
	Level 1(1)	Level 2(1)(2)	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 120	$ 903	$ 12	$ 1,035
Fuel		1	5**(3)**	6
Total Asset Management	120	904	17	1,041
Trading Activities	16	150	17	183
Total derivative contract assets	$ 136	$ 1,054	$ 34	$ 1,224
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 48	$ 180	$ 5	$ 233
Fuel	2	1	115**(3)**	118
Total Asset Management	50	181	120	351
Trading Activities	18	154	9	181
Interest Rate Contracts		50		50
Total derivative contract liabilities	$ 68	$ 385	$ 129	$ 582
Interest-bearing funds**(4)**	$ 2,004	$	$	$ 2,004
Other assets**(5)**	$ 20	$	$	$ 20

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no transfers during the nine months ended September 30, 2012.

(2) Option contracts comprised 1% of net derivative contract assets.

(3) Primarily relates to coal.

(4) Represents investments in money market funds and treasury bills and is included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. Of interest-bearing funds, we had $1.845 billion included in cash and cash equivalents, $54 million included in funds on deposit and $105 million included in other noncurrent assets.

(5) Relates to mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

Table of Contents

	December 31, 2011			
	Level 1(1)	Level 2(1)(2)	Level 3	Total Fair Value
		(in millions)		
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 102	$ 1,136	$ 19	$ 1,257
Fuel	2		9**(3)**	11
Total Asset Management	104	1,136	28	1,268
Trading Activities	124	302	38	464
Total derivative contract assets	$ 228	$ 1,438	$ 66	$ 1,732
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 45	$ 206	$ 2	$ 253
Fuel	19	1	79**(3)**	99
Total Asset Management	64	207	81	352
Trading Activities	142	309	16	467
Interest Rate Contracts		32		32
Total derivative contract liabilities	$ 206	$ 548	$ 97	$ 851
Interest-bearing funds**(4)**	$ 1,985	$	$	$ 1,985
Other assets**(5)**	$ 20	$	$	$ 20

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during 2011.

(2) Option contracts comprised 1% of net derivative contract assets.

(3) Primarily relates to coal.

(4) Represents investments in money market funds and is included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. Of interest-bearing funds, we had $1.626 billion included in cash and cash equivalents, $202 million included in funds on deposit and $157 million included in other noncurrent assets.

(5) Relates to mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

Table of Contents

The following is a reconciliation of changes (comprised of the sum of the quarterly changes) in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during the nine months ended September 30, 2012 and 2011:

	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading Activities (in millions)	Total
Balance, January 1, 2012 (net asset (liability))	$ (53)	$ 22	$ (31)
Total gains (losses) realized/unrealized:			
Included in earnings(1)	(112)	12	(100)
Purchases(2)			
Issuances(2)			
Settlements(3)	62	(26)	36
Transfers into Level 3(4)			
Transfers out of Level 3(4)			
Balance, September 30, 2012 (net asset (liability))	$ (103)	$ 8	$ (95)
Balance, January 1, 2011 (net asset (liability))	$ (70)	$ 2	$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings (1)	5	9	14
Purchases(2)			
Issuances(2)			
Settlements(3)	7	(5)	2
Transfers into Level 3(4)			
Transfers out of Level 3(4)	12		12
Balance, September 30, 2011 (net asset (liability))	$ (46)	$ 6	$ (40)

(1) Represents the fair value, as of the end of each reporting period, of Level 3 contracts entered into during each reporting period and the gains and losses attributable to Level 3 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) Represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each reporting period.

(4) Denotes the total contracts that existed at the beginning of each reporting period and were still held at the end of each reporting period that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during each reporting period. Amounts reflect fair value as of the end of each reporting period.

The following tables present the amounts included in income related to derivative contract assets and liabilities classified as Level 3:

Three Months Ended September 30,	
2012	2011
Total	Total

	Operating Revenues	Cost of Fuel, Electricity and Other Products		Operating Revenues	Cost of Fuel, Electricity and Other Products	
			(in millions)			
Gains (losses) included in income	$ (19)	$ 55	$ 36	$ (3)	$ (10)	$ (13)
Gains (losses) included in income (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at September 30	$ (17)	$ 54	$ 37	$ (2)	$ (11)	$ (13)

Table of Contents

	Nine Months Ended September 30,					
	2012			2011		
	Operating Revenues	Cost of Fuel, Electricity and Other Products	Total	Operating Revenues	Cost of Fuel, Electricity and Other Products	Total
	(in millions)					
Gains (losses) included in income	$ (23)	$ (41)	$ (64)	$ 3	$ 25	$ 28
Gains (losses) included in income (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at September 30	$ (18)	$ (81)	$ (99)	$ 5	$ 23	$ 28

Information about Sensitivity to Changes in Significant Unobservable Inputs. The following table presents the range of sensitivity of unobservable inputs used in fair value measurements categorized within Level 3 of the fair value hierarchy:

	Quantitative Information about Level 3 Fair Value Measurements(1)			
	Net Fair Value at September 30, 2012 (in millions)	Valuation Techniques	Unobservable Input	Range (Weighted Average)
Credit valuation adjustment	$ 1	Internal model	Own credit risk	20% to (20)%(2)

(1) Excludes immaterial unobservable inputs related to power transmission congestion products, power swaps, spread options, physical gas premiums on transactions and credit valuation adjustment related to counterparty credit risk.

(2) Represents the range of the credit default swap spread curves used in the valuation analysis that we think market participants might use when pricing the contracts.

At September 30, 2012, net fair value asset of $10 million for power transactions and net fair value liability of $110 million for fuel transactions classified as Level 3 were priced based on unadjusted indicative broker quotes that cannot be corroborated by observable market data. Quantitative information is excluded for these fair value measurements.

Counterparty Credit Concentration Risk

We are exposed to the default risk of the counterparties with which we transact. We manage our credit risk by entering into master netting agreements and requiring most counterparties to post cash collateral or other credit enhancements based on the net exposure and the credit standing of the counterparty. We also have non-collateralized power hedges entered into by GenOn Mid-Atlantic. These transactions are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties and have not required either party to post cash collateral for initial margin. Since April 2012, the counterparties, in some cases, have been required to post cash collateral to secure credit exposure above an agreed threshold as a result of changes in power or natural gas prices. At September 30, 2012 and December 31, 2011, $108 million and $4 million, respectively, of cash collateral posted by counterparties under master netting agreements were included in accounts payable and accrued liabilities in the consolidated balance sheets. Our credit valuation adjustment on derivative contract assets was $9 million and $48 million at September 30, 2012 and December 31, 2011, respectively.

Table of Contents

We monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. The following tables highlight the credit quality and the balance sheet settlement exposures related to these activities:

	September 30, 2012				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3) (dollars in millions)	Exposure Net of Collateral	% of Net Exposure
Clearing and Exchange	$ 432	$ 159	$ 159	$	
Investment Grade:					
Financial institutions	721	686	106	580	69%
Energy companies	362	228		228	27%
Non-investment Grade:					
Energy companies	8	5	1	4	1%
No External Ratings:					
Internally-rated investment grade	21	19		19	2%
Internally-rated non-investment grade	6	5		5	1%
Total	$ 1,550	$ 1,102	$ 266	$ 836	100%

	December 31, 2011				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3) (dollars in millions)	Exposure Net of Collateral	% of Net Exposure
Clearing and Exchange	$ 724	$ 223	$ 223	$	
Investment Grade:					
Financial institutions	860	817		817	78%
Energy companies	421	195	3	192	18%
Non-investment Grade:					
Energy companies	13	5	1	4	
No External Ratings:					
Internally-rated investment grade	18	18		18	2%
Internally-rated non-investment grade	15	15		15	2%
Total	$ 2,051	$ 1,273	$ 227	$ 1,046	100%

(1) Gross exposure before collateral represents credit exposure, including both realized and unrealized transactions, before (a) applying the terms of master netting agreements with counterparties and (b) netting of transactions with clearing brokers and exchanges. The table excludes amounts related to contracts classified as normal purchases/normal sales and non-derivative contractual commitments that are not recorded at fair value in the consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Non-performance could have a material adverse effect on our future results of operations, financial condition and cash flows.

(2) Net exposure before collateral represents the credit exposure, including both realized and unrealized transactions, after applying the terms of master netting agreements and the netting of transactions with clearing brokers and exchanges.

(3) Collateral includes cash and letters of credit received from counterparties.

We had credit exposure to three and two investment grade counterparties at September 30, 2012 and December 31, 2011, respectively, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $519 million and $664 million at September 30, 2012 and December 31, 2011, respectively.

Table of Contents

GenOn Credit Risk

Our standard industry contracts contain credit-risk-related contingent features such as ratings-related thresholds whereby we would be required to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. Additionally, some of our contracts contain adequate assurance language, which is generally subjective in nature that could require us to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. However, as a result of our current credit rating, we are typically required to post collateral in the normal course of business to offset either substantially or completely the net liability positions, after applying the terms of master netting agreements. At September 30, 2012, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was $22 million for which we had posted collateral of $18 million, including cash and letters of credit.

At September 30, 2012 and December 31, 2011, we had $98 million and $86 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit in the consolidated balance sheets.

Fair Values of Other Financial Instruments

The fair values of certain funds on deposit, accounts receivable, notes and other receivables, and accounts payable and accrued liabilities approximate their carrying amounts.

The carrying amounts and fair values of debt are as follows:

	Carrying Amount	Level 1	Level 2(1) (in millions)	Level 3(2)	Total Fair Value
September 30, 2012					
Liabilities:					
Long and short-term debt	$ 4,371	$	$ 4,349	$ 324	$ 4,673
December 31, 2011					
Liabilities:					
Long and short-term debt	$ 4,132	$	$ 3,969	$ 97	$ 4,066

(1) The fair value of long and short-term debt is estimated using broker quotes for instruments that are publicly traded.

(2) The fair value of long and short-term debt is estimated based on the income approach valuation technique for non-publicly traded debt using current interest rates for similar instruments with equivalent credit quality.

Table of Contents

5. Long-Term Debt

Outstanding debt was as follows:

	September 30, 2012			December 31, 2011		
	Weighted Average Stated Interest Rate(1)	Long-Term	Current	Weighted Average Stated Interest Rate(1)	Long-Term	Current
			(in millions, except interest rates)			
Facilities, Bonds and Notes:						
GenOn:						
Senior unsecured notes, due 2014	7.625%	$ 575	$	7.625%	$ 575	$
Senior unsecured notes, due 2017	7.875	725		7.875	725	
Senior secured term loan, due 2017(2)	6.00	679	7	6.00	684	7
Senior unsecured notes, due 2018	9.50	675		9.50	675	
Senior unsecured notes, due 2020	9.875	550		9.875	550	
Unamortized debt discounts		(22)	(2)		(24)	(2)
GenOn Americas Generation:						
Senior unsecured notes, due 2021	8.50	450		8.50	450	
Senior unsecured notes, due 2031	9.125	400		9.125	400	
Unamortized debt discounts		(2)			(2)	
GenOn Marsh Landing:						
Senior secured term loan, due 2017	2.75	109		2.76	33	
Senior secured term loan, due 2023	3.00	241		3.01	74	
Other:						
Capital leases, due 2015	7.375-8.19	11	5	7.375-8.19	14	5
Adjustment to fair value of debt(3)		(30)			(32)	
Total		$ 4,361	$ 10		$ 4,122	$ 10

(1) The weighted average stated interest rates are at September 30, 2012 and December 31, 2011, respectively.

(2) The debt balance on the term loan facility is recorded at GenOn Americas, a direct subsidiary of GenOn Energy Holdings, because GenOn Americas is a co-borrower.

(3) Debt assumed in the Mirant/RRI Merger was adjusted to fair value on the Mirant/RRI Merger date. The adjustment is amortized to interest expense over various years through 2017.

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At September 30, 2012, outstanding letters of credit were $228 million and availability of borrowings under the revolving credit facility was $560 million.

6. Pension and Other Postretirement Benefit Plans

The components of the net periodic benefit cost (credit) are shown below:

	Pension Plans				Other Postretirement Benefit Plans			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
	(in millions)							
Service cost	$ 3	$ 3	$ 9	$ 9	$	$	$ 1	$
Interest cost	6	5	18	17	1	1	3	3
Expected return on plan assets	(8)	(7)	(23)	(22)				
Net amortization(1)	3	1	7	3	(1)	(1)	(3)	(3)
Special termination benefit	1		1					
Curtailment					(2)		(2)	
Net periodic benefit cost (credit)	$ 5	$ 2	$ 12	$ 7	$ (2)	$	$ (1)	$

(1) Net amortization amounts include actuarial gains/losses and prior service cost/credit.

Table of Contents

7. Stock-Based Compensation

Compensation expense for the stock-based incentive plan was:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions)			
Stock-based incentive plan compensation expense (pre-tax)(1)	$ 6	$ 3	$ 15	$ 11

(1) No tax benefits related to stock-based compensation were realized during the three and nine months ended September 30, 2012 and 2011 because of our NOL carryforwards.

During February 2012, we granted long-term incentive awards as follows:

Award Vehicle	Awards Granted	Vesting Period
Time-based Restricted Stock Units	2,821,302	Vest ratably each year over a three-year period; common stock settled
Performance-based Restricted Stock Units	2,586,482	Linked to the achievement of the 2012 short-term incentive plan performance goals, with performance measured at the end of the first year; vest ratably each year over a three-year period; common stock settled
Stock Options	5,897,990	Vest ratably each year over a three-year period

Vesting in Connection with the NRG Merger. All outstanding stock options (other than options granted in 2012) will immediately vest (to the extent not already fully vested) and all outstanding stock options will generally convert upon completion of the NRG Merger into stock options with respect to NRG common stock, after giving effect to the exchange ratio. In addition, all outstanding restricted stock units (other than restricted stock units granted in 2012) will immediately vest (to the extent not already fully vested) and all outstanding restricted stock units will be exchanged for the NRG Merger consideration. All outstanding stock options and restricted stock units granted in 2012 will vest (to the extent not already fully vested) at the holder s termination date if the termination is as a result of the NRG Merger and within two years of the closing date. See note 1.

8. Earnings Per Share

We calculate basic EPS by dividing income/loss available to stockholders by the weighted average number of common shares outstanding. Diluted EPS gives effect to dilutive potential common shares, including unvested restricted stock units and stock options.

Table of Contents

The following table shows the computation of basic and diluted EPS:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions, except per share data)			
Net loss	$ (85)	$ (40)	$ (345)	$ (289)
Basic and diluted shares				
Weighted average shares outstanding basic	774	772	774	771
Effect of dilutive securities(1)				
Weighted average shares outstanding diluted	774	772	774	771
Basic and Diluted EPS				
Basic EPS	$ (0.11)	$ (0.05)	$ (0.45)	$ (0.37)
Diluted EPS	$ (0.11)	$ (0.05)	$ (0.45)	$ (0.37)

(1) As we incurred a net loss for the three and nine months ended September 30, 2012 and 2011, diluted loss per share is calculated the same as basic loss per share.

The weighted average number of securities that could potentially dilute basic EPS in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive was as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions)			
Stock options	19	17	18	18
Restricted stock units	9	5	8	5
Total number of antidilutive shares	28	22	26	23

9. Accumulated Other Comprehensive Loss

The component balances of accumulated other comprehensive loss, included in the consolidated balance sheets, are as follows:

	September 30, 2012	December 31, 2011
	(in millions)	
Pension and other postretirement benefits actuarial losses, net	$ (145)	$ (142)

Pension and other postretirement benefits prior service credit, net		5		7
Cash flow hedges interest rate swaps		(52)		(34)
Other, net				(1)
Accumulated other comprehensive loss	$	(192)	$	(170)

10. Segment Reporting

We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. The segments are determined based on how the business is managed and align with the information provided to the chief operating decision maker for purposes of assessing performance and allocating resources. Generally, our segments are engaged in the sale of electricity, capacity, and ancillary and other energy services from their generating facilities in hour-ahead, day-ahead and forward markets in bilateral and ISO markets. We also engage in proprietary trading, fuel oil management and natural gas transportation and storage activities. Operating

Table of Contents

revenues consist of (a) power generation revenues, (b) contracted and capacity revenues, (c) power hedging revenues and (d) fuel sales and proprietary trading revenues.

The Eastern PJM segment consists of seven generating facilities located in Maryland and New Jersey. The Western PJM/MISO segment consists of 22 generating facilities located in Illinois, Ohio and Pennsylvania. The California segment consists of seven generating facilities located in California and includes business development and construction activities for GenOn Marsh Landing. See note 2 for a discussion of generating facilities in the Eastern PJM, Western PJM/MISO and California segments that we expect to retire or place in long-term protective layup in 2015. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of seven generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas. Other Operations also includes unallocated overhead expenses and other activity that cannot be identified specifically with another segment. All revenues are generated and long-lived assets are located within the United States.

The following table summarizes changes in our net generating capacity by segment:

	Eastern PJM	**Western PJM/MISO**	**California (in MWs)**	**Other**	**Total**
MWs in service at January 1, 2011	6,336	7,483	5,725	5,055	24,599
Potrero generating facility deactivated in February 2011			(362)		(362)
Rating changes for generating facilities in 2011	5		28	13	46
MWs in service at December 31, 2011	6,341	7,483	5,391	5,068	24,283
Indian River generating facility sold in January 2012				(586)	(586)
Vandolah generating facility expiration of tolling agreement in May 2012				(630)	(630)
Niles unit 2 deactivated in June 2012		(108)			(108)
Elrama units 1-3 deactivated in June 2012		(289)			(289)
MWs in service at September 30, 2012	6,341	7,086	5,391	3,852	22,670
Niles unit 1 deactivated in October 2012		(109)			(109)
Elrama unit 4 deactivated in October 2012		(171)			(171)
Potomac River generating facility deactivated in October 2012	(482)				(482)
MWs in service at November 9, 2012	5,859	6,806	5,391	3,852	21,908

Table of Contents

The measure of profit or loss for our reportable segments is operating income/loss. This measure represents the lowest level of information that is provided to the chief operating decision maker for our reportable segments.

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Three Months Ended September 30, 2012:							
Operating revenues(1)	$ 220	$ 236	$ 209	$ 14	$ 76	$	$ 755
Cost of fuel, electricity and other products(2)	107	154	20	30	35		346
Gross margin (excluding depreciation and amortization)	113	82	189	(16)	41		409
Operating Expenses:							
Operations and maintenance	101	102	34	1	30		268
Depreciation and amortization	34	32	10		15		91
Impairment losses		47(3)					47
Gain on sales of assets, net	(1)						(1)
Total operating expenses	134	181	44	1	45		405
Operating income (loss)	$ (21)	$ (99)	$ 145	$ (17)	$ (4)	$	$ 4

(1) Includes unrealized gains (losses) of $(136) million, $(81) million, $2 million, $(29) million and $(1) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized gains of $46 million, $8 million, $1 million and $3 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Represents long-lived assets impairments, see note 3.

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Nine Months Ended September 30, 2012:							
Operating revenues(1)	$ 772	$ 721	$ 271	$ 65	$ 168	$	$ 1,997
Cost of fuel, electricity and other products(2)	376	399	22	45	88		930
Gross margin (excluding depreciation and amortization)	396	322	249	20	80		1,067
Operating Expenses:							
Operations and maintenance(3)	292(4)	346	117	4	81		840
Depreciation and amortization	101	93	33		42		269

Impairment losses		47(5)					47
Gain on sales of assets, net	(1)	(1)			(7)		(9)
Total operating expenses	392	485	150	4	116		1,147
Operating income (loss)	$ 4	$ (163)	$ 99	$ 16	$ (36)	$	$ (80)
Total assets at September 30, 2012	$ 4,438	$ 3,292	$ 1,106	$ 1,546	$ 3,627(6)	$ (2,434)	$ 11,575

(1) Includes unrealized gains (losses) of $(135) million, $(46) million, $1 million, $(15) million and $(9) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of $26 million, $10 million, $1 million and $(12) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Includes costs to deactivate generating facilities of $11 million, $32 million and $4 million for Eastern PJM, Western PJM/MISO and California, respectively.

(4) Includes $31 million of income related to the reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria.

Table of Contents

(5) Represents long-lived assets impairments, see note 3.

(6) Includes our equity method investment in Sabine Cogen, LP of $20 million.

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Three Months Ended September 30, 2011:							
Operating revenues(1)	$ 346	$ 433	$ 128	$ 88	$ 85	$	$ 1,080
Cost of fuel, electricity and other products(2)	179	206	11	71	59		526
Gross margin (excluding depreciation and amortization)	167	227	117	17	26		554
Operating Expenses:							
Operations and maintenance	99	108	33		46(3)		286
Depreciation and amortization	34	29	11	1	21		96
Impairment losses(4)	95	4	14		20		133
Gain on sales of assets, net			(5)		(1)		(6)
Total operating expenses	228	141	53	1	86		509
Operating income (loss)	$ (61)	$ 86	$ 64	$ 16	$ (60)	$	$ 45

(1) Includes unrealized gains (losses) of $(2) million, $37 million, $1 million, $15 million and $(2) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of $10 million, $1 million, $(1) million and $1 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Includes $24 million of Mirant/RRI Merger-related costs.

(4) Represents impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR.

Table of Contents

	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Nine Months Ended September 30, 2011:							
Operating revenues(1)	$ 962	$ 1,050	$ 200	$ 292	$ 202	$	$ 2,706
Cost of fuel, electricity and other products(2)	433	526	14	222	122		1,317
Gross margin (excluding depreciation and amortization)	529	524	186	70	80		1,389
Operating Expenses:							
Operations and maintenance	351(3)	368	111	2	131(4)		963
Depreciation and amortization	101	88	32	2	49		272
Impairment losses(5)	95	4	14		20		133
Gain on sales of assets, net			(5)				(5)
Total operating expenses	547	460	152	4	200		1,363
Operating income (loss)	$ (18)	$ 64	$ 34	$ 66	$ (120)	$	$ 26
Total assets at December 31, 2011	$ 4,732	$ 3,343	$ 856	$ 2,173	$ 3,662(6)	$ (2,497)	$ 12,269

(1) Includes unrealized gains (losses) of $(80) million, $2 million, $4 million and $(12) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of $(17) million, $(8) million, $(1) million and $(1) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(3) Includes $30 million of expense for large scale remediation and settlement costs.

(4) Includes $61 million of Mirant/RRI Merger-related costs.

(5) Represents impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR.

(6) Includes our equity method investment in Sabine Cogen, LP of $22 million.

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions)			
Operating income (loss) for all segments	$ 4	$ 45	$ (80)	$ 26
Interest expense, net	(85)	(85)	(259)	(290)
Other, net		1	2	(21)
Loss before income taxes	$ (81)	$ (39)	$ (337)	$ (285)

11. Litigation and Other Contingencies

We are involved in a number of legal proceedings. In certain cases, plaintiffs seek to recover large or unspecified damages, and some matters may be unresolved for several years. We cannot currently determine the outcome of the proceedings described below or estimate the reasonable amount or range of potential losses, if any, and therefore have not made any provision for such matters unless specifically noted below.

Scrubber Contract Litigation

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. Stone & Webster claimed that it had not been paid in accordance with the terms of the EPC agreements for the scrubber projects and sought liens against the properties, which the court granted. We disputed Stone & Webster s allegations and in February 2011 filed a related action against Stone &Webster in the United States District Court for the Southern District of New York. The proceedings in Maryland were stayed pending resolution of the proceeding in New York.

Table of Contents

In June 2012, we executed a settlement agreement with Stone & Webster. Under the terms of the settlement agreement GenOn agreed to pay Stone & Webster $107.1 million in settlement of all outstanding invoices and amounts claimed to be owed by Stone & Webster in connection with the construction of the scrubber projects. As part of the settlement, Stone & Webster released the $165.6 million in interlocutory liens that had been filed by Stone & Webster on the Chalk Point, Dickerson and Morgantown generating facilities. As a result of the release of the liens, GenOn Mid-Atlantic released the $165.6 million in reserved cash during June 2012 (previously included as funds on deposit in the consolidated balance sheets). In connection with the settlement agreement, we dismissed our dispute filed in the United States District Court for the Southern District of New York.

We incurred $1.7 billion in capital expenditures from 2007 to 2012 for compliance with the Maryland Healthy Air Act.

Pending Natural Gas Litigation

We are party to five lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits were filed in the aftermath of the California energy crisis in 2000 and 2001 and the resulting FERC investigations and relate to alleged conduct to increase natural gas prices in violation of antitrust and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name a number of unaffiliated energy companies as parties. In July 2011, the judge in the United States District Court for the District of Nevada handling four of the five cases granted the defendants motion for summary judgment dismissing all claims against us in those cases. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. In September 2012, the State of Nevada Supreme Court handling one of the five cases affirmed dismissal by the Eighth Judicial District Court for Clark County, Nevada of all plaintiffs claims against us. In October 2012, the plaintiffs indicated that they intend to file a petition for certiorari to the United States Supreme Court. We have agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

Bowline Property Tax Dispute

In 2011, 2010 and 2009 we filed suit against the town of Haverstraw, New York to challenge the property tax assessment of the Bowline generating facility for each respective tax year. Although the assessments for the 2011 and 2010 tax years were reduced significantly from the assessment received in 2009, they continue to exceed significantly the estimated fair value of the generating facility. The tax litigation for all three years has been combined for trial purposes. While we are unable to predict the outcome of this litigation, if we are successful we expect to receive a refund for each of the years under protest.

Environmental Matters

Global Warming. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a suit in the United States District Court for the Northern District of California against GenOn and 23 other electric generating and oil and gas companies. The lawsuit sought damages of up to $400 million for the cost of relocating the village allegedly because of global warming caused by the greenhouse gas emissions of the defendants. In late 2009, the District Court ordered that the case be dismissed and the plaintiffs appealed. In September 2012, the United States Court of Appeals for the Ninth Circuit dismissed planitiffs appeal. In October 2012, the plaintiffs petitioned for en banc rehearing of the case. Although we think claims such as this lack legal merit, it is possible that this trend of climate change litigation may continue.

New Source Review Matters. The EPA and various states are investigating compliance of coal-fueled electric generating facilities with the pre-construction permitting requirements of the Clean Air Act known as new source review. Since 2000, the EPA has made information requests concerning the 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. The EPA agreed to share information relating to its investigations with state environmental agencies. In January 2009, we received an NOV from the EPA alleging that past work at our Shawville, Portland and Keystone generating facilities violated regulations regarding new source review. In June 2011, we received an NOV from the EPA alleging that past work at our Niles and Avon Lake generating facilities violated regulations regarding new source review.

Table of Contents

In December 2007, the NJDEP filed suit against us in the United States District Court for the Eastern District of Pennsylvania, alleging that new source review violations occurred at the Portland generating facility. The suit seeks installation of best available control technologies for each pollutant, to enjoin us from operating the generating facility if it is not in compliance with the Clean Air Act and civil penalties. The suit also names three past owners of the plant as defendants. In March 2009, the Connecticut Department of Environmental Protection became an intervening party to the suit.

We think that the work listed by the EPA and the work subject to the NJDEP suit were conducted in compliance with applicable regulations. However, any final finding that we violated the new source review requirements could result in fines, penalties or significant capital expenditures associated with the implementation of emissions reductions on an accelerated basis. Most of these work projects were undertaken before our ownership or lease of those facilities.

In addition, the NJDEP filed two administrative petitions with the EPA in 2010 alleging that our Portland generating facility s emissions were significantly contributing to nonattainment and/or interfering with the maintenance of certain NAAQS in New Jersey. In November 2011, the EPA published a final rule in response to one of the petitions that will require us to reduce our maximum allowable SO_2 emissions from the two coal-fired units by about 60% starting in January 2013 and by about 80% starting in January 2015. In January 2012, we challenged the rule in the United States Court of Appeals for the Third Circuit. In 2013 and 2014, we have several compliance options that include using lower sulfur coals (although this may at times reduce how much we are able to generate) or running just one unit at a time. Starting in January 2015, these units will be subject to more stringent rate limits, which will require either material capital expenditures and higher operating costs or the retirement of these two units. See note 2 for a discussion of the Portland coal-fired units that we expect to deactivate in 2015.

Cheswick Class Action Complaint. In April 2012, a putative class action lawsuit was filed against us in the Court of Common Pleas of Allegheny County, Pennsylvania alleging that emissions from our Cheswick generating facility have damaged the property of neighboring residents. We dispute these allegations. Plaintiffs have brought nuisance, negligence, trespass and strict liability claims seeking both damages and injunctive relief. Plaintiffs seek to certify a class that consists of people who own property or live within one mile of our plant. In July 2012, we removed the lawsuit to the United States District Court for the Western District of Pennsylvania. In October 2012, the court granted our motion to dismiss. Plaintiffs have 30 days to appeal this order.

Cheswick Monarch Mine NOV. In 2008, the PADEP issued an NOV related to the Monarch mine located near our Cheswick generating facility. It has not been mined for many years. We use it for disposal of low-volume wastewater from the Cheswick generating facility and for disposal of leachate collected from ash disposal facilities. The NOV addresses the alleged requirement to maintain a minimum pumping volume from the mine. The PADEP indicated it may assess a civil penalty in excess of $100,000. We contest the allegations in the NOV and have not agreed to such penalty. We are currently planning capital expenditures in connection with wastewater from Cheswick and leachate from ash disposal facilities.

Conemaugh Alleged Clean Streams Law Violations. In September 2012, the PADEP filed a lawsuit in the Commonwealth Court of Pennsylvania alleging that several violations of the Pennsylvania Clean Streams Law occurred at the Conemaugh generating facility. We have negotiated a proposed consent decree to address the allegations. We expect that the proposed consent decree, which has been lodged with the court, will resolve these issues and obligate us to pay a civil penalty of $500,000. We are responsible for 16.45% of this amount.

Ormond Beach Alleged Federal Clean Water Act Violations. In October 2012, the Wishtoyo Foundation, a California-based cultural and environmental advocacy organization, through its Ventura Coastkeeper Program, filed suit in the United States District Court for the Central

District of California regarding alleged violations of the Clean Water Act associated with discharges of stormwater from the Ormond Beach generating facility. The Wishtoyo Foundation alleges that elevated concentrations of pollutants in stormwater discharged from the Ormond Beach generating facility are affecting adjacent aquatic resources in violation of (a) the Statewide General Industrial Stormwater permit (a general National Pollution Discharge Elimination System permit issued by the California State Water Resources Control Board that authorizes stormwater discharges from industrial facilities in California) and (b) the state s Porter-Cologne Water Quality Control Act. The Wishtoyo Foundation further alleges that we have

Table of Contents

not implemented effective stormwater control and treatment measures and that we have not complied with the sampling and reporting requirements of the General Industrial Stormwater permit. We dispute these allegations.

Maryland Fly Ash Facilities. We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. We dispose of fly ash from our Morgantown and Chalk Point generating facilities at Brandywine. We dispose of fly ash from our Dickerson generating facility at Westland. We no longer dispose of fly ash at the Faulkner facility. As described below, the MDE has sued us regarding Faulkner and Brandywine and threatened to sue regarding Westland. The MDE also had threatened not to renew the water discharge permits for all three facilities.

Faulkner Litigation. In May 2008, the MDE sued us in the Circuit Court for Charles County, Maryland alleging violations of Maryland s water pollution laws at Faulkner. The MDE contended that the operation of Faulkner had resulted in the discharge of pollutants that exceeded Maryland s water quality criteria and without the appropriate NPDES permit. The MDE also alleged that we failed to perform certain sampling and reporting required under an applicable NPDES permit. The MDE complaint requested that the court (a) prohibit continuation of the alleged unpermitted discharges, (b) require us to cease from further disposal of any coal combustion byproducts at Faulkner and close and cap the existing disposal cells and (c) assess civil penalties. In July 2008, we filed a motion to dismiss the complaint, arguing that the discharges are permitted by a December 2000 Consent Order. In January 2011, the MDE dismissed without prejudice its complaint and informed us that it intended to file a similar lawsuit in federal court. In May 2011, the MDE filed a complaint against us in the United States District Court for the District of Maryland alleging violations at Faulkner of the Clean Water Act and Maryland s Water Pollution Control Law. The MDE contends that (a) certain of our water discharges are not authorized by our existing permit and (b) operation of the Faulkner facility has resulted in discharges of pollutants that violate water quality criteria. The complaint asks the court to, among other things, (a) enjoin further disposal of coal ash; (b) enjoin discharges that are not authorized by our existing permit; (c) require numerous technical studies; (d) impose civil penalties and (e) award MDE attorneys fees. We dispute the allegations.

Brandywine Litigation. In April 2010, the MDE filed a complaint against us in the United States District Court for the District of Maryland asserting violations at Brandywine of the Clean Water Act and Maryland s Water Pollution Control Law. The MDE contends that the operation of Brandywine has resulted in discharges of pollutants that violate Maryland s water quality criteria. The complaint requests that the court, among other things, (a) enjoin further disposal of coal combustion waste at Brandywine, (b) require us to close and cap the existing open disposal cells within one year, (c) impose civil penalties and (d) award MDE attorneys fees. We dispute the allegations. In September 2010, four environmental advocacy groups became intervening parties in the proceeding.

Threatened Westland Litigation. In January 2011, the MDE informed us that it intended to sue us for alleged violations at Westland of Maryland s water pollution laws. To date, MDE has not sued us regarding our ash disposal.

Permit Renewals. In March 2011, the MDE tentatively determined to deny our application for the renewal of the water discharge permit for Brandywine, which could result in a significant increase in operating expenses for our Chalk Point and Morgantown generating facilities. The MDE also had indicated that it was planning to deny our applications for the renewal of the water discharge permits for Faulkner and Westland. Denial of the renewal of the water discharge permit for the latter facility could result in a significant increase in operating expenses for our Dickerson generating facility.

Stay and Settlement Discussions. In June 2011, the MDE agreed to stay the litigation related to Faulkner and Brandywine while we pursued settlement of allegations related to the three Maryland ash facilities. MDE also agreed not to pursue its tentative denial of our application to renew our water discharge permit at Brandywine and agreed not to act on our renewal applications for Faulkner or Westland while we were discussing settlement. As a condition to obtaining the stay, we agreed in principle to pay a civil penalty of $1.9 million (for alleged past violations) to the MDE if we reach a comprehensive settlement regarding all of the allegations related to the three Maryland ash facilities. We accrued $1.9 million during 2011 and an additional $0.6 million (for agreed prospective penalties while we implement the settlement) during the second quarter of 2012 for a total of $2.5 million. We also developed a technical solution, which includes installing synthetic caps on the closed cells of each of the three ash facilities. During 2011, we accrued $47 million for the estimated cost of the technical solution. We have nearly

Table of Contents

concluded our settlement discussions with the MDE. At this time, we cannot reasonably estimate the upper range of our obligations for remediating the sites for the following reasons: (a) we have not finished assessing each site including identifying the full impacts to both ground and surface water and the impacts to the surrounding habitat; (b) we have not finalized with the MDE the standards to which we must remediate; and (c) we have not identified the technologies required, if any, to meet the mandated remediation standards at each site nor the timing of the design and installation of such technologies.

Brandywine Storm Damage and Ash Recovery. As a result of Hurricane Irene and Tropical Storm Lee in August and September 2011, an estimated 8,800 cubic yards of coal fly ash stored in one of the cells at the Brandywine ash disposal site flowed onto 18 acres of private property adjacent to the site. During 2011, we accrued $10 million for the estimated costs to remove and clean up the ash. We have removed the released ash from the private property and completed the remaining clean-up activities. We adjusted our estimate and reversed $4 million during the second quarter of 2012. During the third quarter of 2012, we received $2 million of insurance proceeds in connection with our claims associated with the costs to remove and clean up the ash.

Brandywine Filling of Wetlands. While expanding and installing a liner at the Brandywine ash disposal site, we inadvertently filled wetlands without having all of the requisite permits. The MDE also has alleged that we violated the notice requirements of our sediment and erosion control plan. In July 2012, the MDE filed a complaint in the Circuit Court for Prince George s County, Maryland for civil penalties and injunctive relief in connection with the storm damage and the filling of the wetlands. We have agreed to settle these matters by paying a fine of $300,000.

Ash Disposal Facility Closures. We are responsible for environmental costs related to the future closures of several ash disposal facilities. We have accrued the estimated discounted costs ($40 million and $38 million at September 30, 2012 and December 31, 2011, respectively) associated with these environmental liabilities as part of the asset retirement obligations. These amounts are exclusive of the $47 million accrual for the technical solution for the three ash facilities in Maryland discussed above.

Remediation Obligations. We are responsible under the Industrial Site Recovery Act for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. We have accrued the estimated long-term liability for the remediation costs of $6 million at September 30, 2012 and December 31, 2011.

Chapter 11 Proceedings

In July 2003, and various dates thereafter, the Mirant Debtors filed voluntary petitions in the Bankruptcy Court for relief under Chapter 11 of the United States Bankruptcy Code. GenOn Energy Holdings and most of the other Mirant Debtors emerged from bankruptcy on January 3, 2006, when the Plan became effective. The remaining Mirant Debtors emerged from bankruptcy on various dates in 2007. Approximately 461,000 of the shares of GenOn Energy Holdings common stock to be distributed under the Plan have not yet been distributed and have been reserved for distribution with respect to claims disputed by the Mirant Debtors that have not been resolved. Upon the Mirant/RRI Merger, those reserved shares converted into a reserve for approximately 1.3 million shares of GenOn common stock. Under the terms of the Plan, upon the resolution of such a disputed claim, the claimant will receive the same pro rata distributions of common stock, cash, or both as previously allowed claims, regardless of the price at which the common stock is trading at the time the claim is resolved. If the aggregate amount of any such payouts results in the number of reserved shares being insufficient, additional shares of common stock may be issued to address the shortfall.

Actions Pursued by MC Asset Recovery

Under the Plan, the rights to certain actions filed by GenOn Energy Holdings and some of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly-owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is now governed by a manager who is independent of us. Under the Plan, any cash recoveries obtained by MC Asset Recovery from the actions transferred to it, net of fees and costs incurred in prosecuting the actions, are to be paid to the unsecured creditors of GenOn Energy Holdings in the Chapter 11 proceedings and the holders of the equity interests in GenOn Energy Holdings immediately prior to the effective

Table of Contents

date of the Plan except where such a recovery results in an allowed claim in the bankruptcy proceedings, as described below. MC Asset Recovery is a disregarded entity for income tax purposes, and GenOn Energy Holdings is responsible for income taxes related to its operations. The Plan provides that GenOn Energy Holdings may not reduce payments to be made to unsecured creditors and former holders of equity interests from recoveries obtained by MC Asset Recovery for the taxes owed by GenOn Energy Holdings, if any, on any net recoveries up to $175 million. If the aggregate recoveries exceed $175 million net of costs, then GenOn Energy Holdings may reduce the payments by the amount of any taxes it will owe or NOLs utilized with respect to taxable income resulting from the amount in excess of $175 million.

The Plan and the MC Asset Recovery Limited Liability Company Agreement also obligate GenOn Energy Holdings to make contributions to MC Asset Recovery as necessary to pay professional fees and certain other costs. In June 2008, GenOn Energy Holdings and MC Asset Recovery, with the approval of the Bankruptcy Court, agreed to limit the total amount of funding to be provided by GenOn Energy Holdings to MC Asset Recovery to $68 million, and the amount of such funding obligation not already incurred by GenOn Energy Holdings at that time was fully accrued. GenOn Energy Holdings was entitled to be repaid the amounts it funded from any recoveries obtained by MC Asset Recovery before any distribution was made from such recoveries to the unsecured creditors of GenOn Energy Holdings and the former holders of equity interests.

In March 2009, Southern Company and MC Asset Recovery entered into a settlement agreement resolving claims asserted by MC Asset Recovery in a suit that was pending in the United States District Court for the Northern District of Georgia. Southern Company paid $202 million to MC Asset Recovery in settlement of all claims asserted in the litigation. MC Asset Recovery used a portion of that payment to pay fees owed to the managers of MC Asset Recovery and other expenses of MC Asset Recovery not previously funded by GenOn Energy Holdings, and it retained $47 million from that payment to fund future expenses and to apply against unpaid expenditures. MC Asset Recovery distributed the remaining $155 million to GenOn Energy Holdings. In accordance with the Plan, GenOn Energy Holdings retained approximately $52 million of that distribution as reimbursement for the funds it had provided to MC Asset Recovery and costs it incurred related to MC Asset Recovery that had not been previously reimbursed. GenOn Energy Holdings recognized the $52 million as a reduction of operations and maintenance expense during 2009. Pursuant to MC Asset Recovery s Limited Liability Company Agreement and an order of the Bankruptcy Court dated October 31, 2006, GenOn Energy Holdings distributed $2 million to the managers of MC Asset Recovery. In September 2009, the remaining approximately $101 million of the amount recovered by MC Asset Recovery was distributed pursuant to the terms of the Plan. Following these distributions, GenOn Energy Holdings has no further obligation to provide funding to MC Asset Recovery. As a result, GenOn Energy Holdings reversed its remaining accrual of $10 million of funding obligations as a reduction in operations and maintenance expense for 2009. GenOn does not expect to owe any taxes related to the MC Asset Recovery settlement with Southern Company.

Based on a stipulation entered by the Bankruptcy Court in December 2011 and pursuant to the terms of the Plan and the MC Asset Recovery Limited Liability Company Agreement, during March 2012, GenOn Energy Holdings distributed $26 million of the $47 million in funds that had been previously retained by MC Asset Recovery.

One of the two remaining actions transferred to MC Asset Recovery seeks to recover damages from Commerzbank AG and various other banks (the Commerzbank Defendants) for alleged fraudulent transfers that occurred prior to the filing of GenOn Energy Holdings bankruptcy proceedings. In its amended complaint, MC Asset Recovery alleges that the Commerzbank Defendants in 2002 and 2003 received payments totaling approximately 153 million Euros directly or indirectly from GenOn Energy Holdings under a guarantee provided by GenOn Energy Holdings in 2001 of certain equipment purchase obligations. MC Asset Recovery alleges that at the time GenOn Energy Holdings provided the guarantee and made the payments to the Commerzbank Defendants, GenOn Energy Holdings was insolvent and did not receive fair value for those transactions. In December 2010, the United States District Court for the Northern District of Texas dismissed MC Asset Recovery s complaint against the Commerzbank Defendants. In January 2011, MC Asset Recovery appealed the United States District Court s dismissal of its complaint against the Commerzbank Defendants to the United States Court of Appeals for the Fifth Circuit. In March 2012, the United States Court of Appeals for the Fifth Circuit reversed the United States District Court s dismissal and reinstated MC Asset Recovery s amended complaint against the Commerzbank Defendants. If MC Asset Recovery succeeds in obtaining any recoveries on these avoidance claims, the Commerzbank

Table of Contents

Defendants have asserted that they will seek to file claims in GenOn Energy Holdings bankruptcy proceedings for the amount of those recoveries. GenOn Energy Holdings would vigorously contest the allowance of any such claims on the ground that, among other things, the recovery of such amounts by MC Asset Recovery does not reinstate any enforceable pre-petition obligation that could give rise to a claim. If such a claim were to be allowed by the Bankruptcy Court as a result of a recovery by MC Asset Recovery, then the Plan provides that the Commerzbank Defendants are entitled to the same distributions as previously made under the Plan to holders of similar allowed claims. Holders of previously allowed claims similar in nature to the claims that the Commerzbank Defendants would seek to assert have received 43.87 shares of GenOn Energy Holdings common stock for each $1,000 of claim allowed by the Bankruptcy Court. If the Commerzbank Defendants were to receive an allowed claim as a result of a recovery by MC Asset Recovery on its claims against them, the order entered by the Bankruptcy Court in December 2005, confirming the Plan provides that GenOn Energy Holdings would retain from the net amount recovered by MC Asset Recovery an amount equal to the dollar amount of the resulting allowed claim rather than distribute such amount to the unsecured creditors and former equity holders as described above.

Texas Franchise Audit

In 2008 and 2009, the State of Texas, as a result of its audit, issued franchise tax assessments against us indicating an underpayment of franchise tax of $72 million (including interest and penalties through September 30, 2012 of $29 million). These assessments are related primarily to a claim by Texas that would change the sourcing of intercompany receipts for the years 2000 through 2006, thereby increasing the amount of tax due to Texas. We disagree with most of the State s assessment and its determination of the related tax liability. Given the disagreement with the State s position, we have accrued a portion of the liability but have protested the entire assessment and are currently in the administrative appeals process. If we do not fully resolve or come to satisfactory settlement of the protested issues, then we could pay up to the entire amount of the assessed tax, penalties and interest. We intend to defend fully our position in the administrative appeals process and if such defense requires litigation, would be required to pay the full assessment and sue for refund.

NRG Merger Litigation

During July and August 2012, we, the members of our board of directors, NRG, and Plus Merger Corporation (a wholly-owned subsidiary of NRG) were named defendants in nine purported class action lawsuits filed in the Court of Chancery of the State of Delaware, one of which has been dismissed and the remainder of which were consolidated into one action (*In re GenOn Energy, Inc. Shareholders Litigation, Consolidated C.A. No. 7721-VCN*). In October 2012, we signed a memorandum of understanding to settle the Delaware consolidated action based on additional disclosures that were provided to stockholders.

In July 2012, we, the members of our board of directors, NRG, and Plus Merger Corporation were also named defendants in three purported class action lawsuits filed in the 189th District Court of Harris County, Texas, which have been consolidated into one action (*Akel, et al. v. GenOn Energy, Inc., et al., Consolidated Case No. 2012-42090*) and one purported class action lawsuit filed in the United States District Court for the Southern District of Texas (*Bushansky v. GenOn Energy, Inc. et al., No. 4:12-CV-02257*). In October 2012, the United States District Court for the Southern District of Texas issued an order granting the parties joint motion to stay the action until the later of the resolution of a motion for injunction or the final settlement of the Delaware consolidated action, which is discussed above.

Each case was brought on behalf of proposed classes consisting of holders of our common stock, excluding defendants and their affiliates. The complaints allege, among other things, that (a) the NRG Merger Agreement was the product of breaches of fiduciary duties by the individual defendants, in that it allegedly does not maximize the value for our stockholders and that the individual defendants acted in their own self-interest in negotiating the transaction, (b) the joint proxy statement contains incomplete and misleading disclosures and (c) the other defendants aided and abetted the individual defendants breaches of fiduciary duties. The complaints seek, among other things, (a) a declaration that the NRG Merger Agreement was entered into in breach of the defendants duties, (b) to enjoin defendants from consummating the NRG Merger, (c) directing the defendants to exercise their duties to obtain a transaction which is in the best interests of our stockholders, (d) granting the class members any benefits allegedly improperly received by the defendants, (e) a rescission of the NRG Merger if it is consummated and/or (f)

Table of Contents

an order directing additional disclosure regarding the NRG Merger. We think that the allegations of the complaints are without merit and that we have substantial meritorious defenses to the claims made in these actions. See note 1.

Table of Contents

ITEM 2. 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 interim financial statements, the changes in those financial statements from period to period and the primary factors contributing to those changes. The following discussion should be read in conjunction with our interim financial statements and our 2011 Annual Report on Form 10-K.

Overview

We are a wholesale generator with approximately 22,000 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. See note 10 to our interim financial statements. We also operate integrated asset management and proprietary trading operations. Our customers are principally ISOs, RTOs and investor-owned utilities.

Our generating capacity is 56% in PJM, 25% in CAISO, 12% in NYISO and ISO NE, 6% in the Southeast and 1% in MISO. The net generating capacity of these facilities consists of approximately 38% baseload, 43% intermediate and 19% 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.

Proposed Merger with NRG. On July 20, 2012, we entered into the NRG Merger Agreement with NRG Energy, Inc. and a direct wholly-owned subsidiary of NRG. Upon the terms and subject to the conditions set forth in the NRG Merger Agreement, which has been approved by the boards of directors of GenOn and NRG, a wholly-owned subsidiary of NRG will merge with and into GenOn, with GenOn continuing as the surviving corporation and a wholly owned subsidiary of NRG. Upon closing of the NRG Merger, each issued and outstanding share of our common stock will automatically convert into the right to receive 0.1216 shares of common stock of NRG based on the exchange ratio. See notes 1, 7 and 11 to our interim financial statements.

Retirements, Mothballing or Long-Term Protective Layup of Generating Facilities

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 deactivated the following coal-fired units at the referenced times: Niles unit 2 (108 MW) June 2012, Niles unit 1 (109 MW) October 2012, Elrama units 1-3 (289 MW) mothballed June 2012 (plan to retire in March 2014) and Elrama unit 4 (171 MW) mothballed October 2012 (plan to retire in March 2014). We expect to deactivate the following generating capacity, primarily coal-fired units, at the referenced times: Portland (401 MW) January 2015, Gilbert unit 8 (90 MW) January 2015, Avon Lake (732 MW) April 2015, New Castle (330 MW) April 2015, Titus (243 MW) April 2015, Shawville (597 MW) place in long-term protective layup in April 2015 and Glen Gardner (160 MW) May 2015. The foregoing generating facilities with an aggregate of 3,230 MW contributed 13% to our realized gross margin during the year of 2011. We filed for RMR arrangements for Niles unit 1 and Elrama unit 4 that were in effect from June 1 through September 30, 2012. See Regulatory Matters below for further discussion.

We expect industry retirements of coal-fired generating facilities to contribute to a tightening of supply and demand fundamentals and to higher prices for the remaining generating facilities which will more than offset reduced earnings from our unit deactivations. We expect the resulting higher market prices to provide adequate returns on investment in environmental controls necessary to meet promulgated and anticipated requirements at certain of our facilities. Accordingly, we expect to invest approximately $621 million to $738 million over the next decade for selective catalytic reduction emissions controls and other major environmental controls to meet certain air and water quality requirements, which we expect to fund from existing sources of liquidity.

Table of Contents

In addition to the deactivations of the above facilities, we retired our Potomac River facility in October 2012 and plan to retire our Contra Costa facility in May 2013. See note 2 to our interim financial statements.

If market conditions and/or environmental and regulatory factors or assumptions change in the future, forecasted returns on investments necessary to comply with environmental regulations could change resulting in possible incremental investments if returns improve or deactivation of additional generating units or facilities if returns deteriorate. Such deactivations could result in additional charges, including impairments, severance costs and other plant shutdown costs.

Long-Lived Assets Impairments

We determined that the Portland and Titus generating facilities were impaired at September 30, 2012, as the carrying values exceeded the undiscounted cash flows and recognized impairment losses of $47 million during the third quarter of 2012. See note 3.

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 GenOn Mid-Atlantic and the counterparties. At October 8 2012, our aggregate hedge levels based on expected generation for each year were as follows:

	2012(1)	**2013**	**2014**	**2015**	**2016**
Power	80%	75%	49%	22%	13%
Fuel	88%	35%	17%	11%	11%

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

Dodd-Frank Act

The Dodd-Frank Act, which was enacted in July 2010, increases the regulation of transactions involving OTC derivative financial instruments. 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. The CFTC and the United States Securities and Exchange

Commission adopted a joint rule further defining the terms swap dealer and major swap participant, among others. We have reviewed the definitions in the rule to determine the impact, if any, on our commercial activity. Based on the analysis of our facts and circumstances, we do not think that our commercial activity results in our designation as a swap dealer or major swap participant. Accordingly, we will not be subject to the direct costs and additional reporting and business conduct rules imposed on swap dealers and major swap participants. However, the imposition of such costs and additional regulatory burdens on other market participants may reduce liquidity in the markets in which we transact and, thus, may substantially increase the cost of or even limit our ability to effectively hedge.

Capital Expenditures and Capital Resources

During the nine months ended September 30, 2012, we invested $463 million for capital expenditures, excluding capitalized interest paid. Capital expenditures for the period primarily related to the construction of the Marsh Landing generating facility, a $107.1 million settlement payment resulting from the scrubber contract litigation, and maintenance capital expenditures. We incurred $1.7 billion in capital expenditures from 2007 to 2012

Table of Contents

for compliance with the Maryland Healthy Air Act. See note 11 to our interim financial statements for further discussion of the scrubber contract litigation settlement.

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 the remainder of 2012 and 2013:

	October 1, 2012 through December 31, 2012	2013
	(in millions)	
Maintenance	$ 37	$ 138
Environmental	19	118
Construction:		
Marsh Landing generating facility	108	65
Other	4	3
Other	2	9
Total	$ 170	$ 333

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 from 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

CSAPR. 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 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 ruled on the legal deficiencies alleged with respect to the CSAPR. The CSAPR would have addressed interstate transport of emissions of NO_x and SO_2. The CSAPR would have established 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 would have created emission budgets for each of the covered states and allocated emissions allowances (denominated in tons of emissions) to each of the 28 states

Table of Contents

regulated under the CSAPR. In August 2012, the D.C. Circuit issued an opinion vacating the CSAPR and keeping CAIR in place. In October 2012, the EPA filed a petition asking the D.C. Circuit to rehear the case *en banc*.

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 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 were consolidated and in June 2012, the D.C. Circuit denied or dismissed the petitions seeking review of these rules.

In April 2012, the EPA proposed a rule under the New Source Performance Standard section of the Clean Air Act that will limit the CO_2 emissions from new fossil-fuel-fired boilers, integrated gasification combined cycle units and stationary combined cycle turbine units greater than 25 MWs. The proposed limit is 1000 pounds of CO_2 per MWh, which cannot be achieved by coal-fired units unless technology to capture and store CO_2 is installed, which is not commercially available and faces several unresolved legal and regulatory issues. The proposed rule does not apply to simple cycle combustion turbines or existing units. Even though this proposed rule has not been finalized, it is applicable from the time it was proposed unless the EPA issues a final rule that is different or the courts or the United States Congress modify it. We expect the EPA to issue another rule that will require states to develop CO_2 standards that would be applicable to existing fossil-fueled generating facilities.

Canal NPDES and SWD Permit. In August 2008, the EPA renewed the NPDES permit for the Canal generating facility but sought to impose a requirement that the facility install a closed cycle cooling system. The same permit was concurrently issued by MADEP as a state SWD permit. We appealed both the NPDES permit and the SWD permit. In December 2008, the EPA requested a stay to the appeal proceedings, withdrew the provisions related to the closed cycle cooling requirements and re-noticed those provisions for additional public comment. Rather than grant the stay sought by the EPA, the Environmental Appeals Board has dismissed the appeal without prejudice. The parallel MADEP proceeding, which had been stayed, also has been dismissed without prejudice. In the absence of permit renewals, the Canal generating facility will continue to operate under its current NPDES and SWD permits.

Regulatory Matters

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. 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.

PJM. In January 2011, New Jersey enacted legislation which requires the New Jersey 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. In May 2012, two of the three projects were accepted as a capacity resource in the 2015/2016 RPM capacity auction, while the third project failed to clear the auction. Because the law could have a negative effect on capacity prices in PJM in future years, in February 2011, a group of companies filed suit in the

Table of Contents

U.S. District Court for the District of New Jersey asking the court to declare the New Jersey legislation unconstitutional. We are not a party to the ongoing proceeding.

In September 2011, the MPSC issued a request for proposal 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 order provided for project submittals and a MPSC hearing 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 MPSC stating there is no need for additional capacity at this time. In April 2012, the MPSC ordered the state s three public utility companies to enter into a contract with CPV Maryland, LLC for the output of a new 661 MW combined cycle facility in the Southwestern Mid-Atlantic Area Council zone of PJM to be constructed and operational by 2015. The contract required the generating facility be bid into the PJM capacity market in a manner consistent with the PJM tariff. CPV Maryland, LLC bid into the PJM capacity market for the 2015/2016 auction year and cleared the auction. In April 2012, certain companies (not including us) filed in the U.S. District Court for the District of Maryland a complaint for declaratory and injunctive relief barring the implementation of the MPSC order. There have been petitions for judicial review of the administrative record filed by certain companies (not including us) in various circuit courts in Maryland. It is possible that the MPSC will continue to seek additional contracts for new generating capacity. Such contracts could result in reduced future capacity prices and energy prices in PJM.

Some companies (including us) have publicly indicated that they intend to pursue changes in the PJM auction rules to ensure that future RPM auctions are not adversely affected as a result of such contracting and bidding practices.

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 to be established for each planning year. In June 2012, the FERC issued an order accepting many elements of the MISO filing; however, the FERC rejected the requirement of a mandatory capacity auction and instead implemented a voluntary auction for load serving entities that were capacity deficient for the planning year. The FERC directed MISO to make further filings to implement the June 2012 FERC order. Depending upon the timing of the FERC s acceptance of MISO s additional filings, the first voluntary auction will 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.

RMR. In May 2012, we filed with the FERC an RMR rate schedule governing operation of unit 4 of the Elrama generating facility and unit 1 of the Niles generating facility. PJM determined that each of these units was needed past their planned deactivation date of June 1, 2012 to maintain transmission system reliability on the PJM system pending the completion of transmission upgrades. The RMR rate schedule sets forth the terms, conditions and cost-based rates under which we operated the units for reliability purposes through September 30, 2012, the date PJM indicated the units would no longer be needed for reliability. In July 2012, the FERC accepted our RMR rate schedule subject to hearing and settlement procedures. In the settlement discussions ordered by the FERC or in any subsequent hearing, our RMR rate schedule may be modified from that which we filed. The rates we charged are subject to refund pending a ruling or settlement.

Commodity Prices and Generation Volumes

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

Table of Contents

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 for 2012 compared with 2011.

We experienced a decrease in power generation volumes during the nine months ended September 30, 2012, as compared to the same period in 2011, particularly in our Eastern PJM and Western PJM/MISO segments. The decrease in generation occurred primarily at our coal-fired facilities and was caused primarily by contracting dark spreads resulting from decreasing natural gas prices. Consequently, we have significant coal inventories at our generating facilities and, in the case of our Mid-Atlantic facilities, such inventories were at the maximum available storage capacity of such facilities. In April 2012, we issued notices of force majeure under the respective coal contracts as it was impossible for us to take coal at such facilities. In August 2012, we issued notices to the affected coal suppliers that the force majeure conditions have abated and, accordingly, we resumed shipments in accordance with the coal contracts. A number of the suppliers disputed our invocation of force majeure. In our communications with the affected coal suppliers, we have advised them that we expect to take all the coal for which we have contracted, at the contracted prices, as we are able to do so.

Capacity Sales

Capacity sales, whether made bilaterally or through periodic auction processes in the ISO and RTO markets in which we participate, provide an important source of predictable revenues for us over the contracted periods. In the May 2012 PJM RPM auction we secured over $500 million of capacity revenue for the planning year 2015/2016. At October 8, 2012, total projected contracted capacity and PPA revenues for which prices have been set for the last three months of 2012 and 2013-2016 are $3.1 billion.

Results of Operations

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 net income/loss and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. As indicated above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted net income/loss and adjusted EBITDA also exclude, as applicable: (a) Mirant/RRI Merger-related costs, (b) NRG Merger-related costs, (c) lower of cost or market adjustments to our commodity inventories, net of recoveries, (d) impairment losses, (e) gain/loss on early extinguishment of debt, (f) large scale remediation and settlement costs, (g) major litigation costs, net of recoveries, (h) costs to deactivate generating facilities, (i) advance settlement of an out-of-market contract obligation, (j) reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria and (k) certain other items. 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

Table of Contents

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 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.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Consolidated Financial Performance

We reported a net loss of $85 million and $40 million during the three months ended September 30, 2012 and 2011, respectively. The change in net loss is detailed as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011 (in millions)	Increase/ (Decrease)
Realized gross margin	$ 596	$ 516	$ 80
Unrealized gross margin	(187)	38	(225)
Total gross margin (excluding depreciation and amortization)	409	554	(145)
Operating expenses:			
Operations and maintenance	268	286	(18)
Depreciation and amortization	91	96	(5)
Impairment losses	47	133	(86)
Gain on sales of assets, net	(1)	(6)	5
Total operating expenses	405	509	(104)
Operating income	4	45	(41)
Other income (expense), net:			
Interest expense, net	(85)	(85)	
Other, net		1	1
Total other expense, net	(85)	(84)	1
Loss before income taxes	(81)	(39)	(42)
Provision for income taxes	4	1	3
Net loss	$ (85)	$ (40)	$ (45)

Realized Gross Margin. Our realized gross margin increase of $80 million was principally a result of the following:

- $67 million increase in contracted and capacity primarily resulting from higher capacity prices in our California segment;

- $10 million increase in energy, primarily as a result of an $11 million increase in our Energy Marketing segment primarily as a result of decreases in losses from fuel oil management activities; and

- $3 million increase in realized value of hedges, primarily as a result of a $59 million increase in power hedges primarily resulting from lower prices, offset in part by a $56 million decrease in coal and gas hedges primarily resulting from lower prices.

Table of Contents

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

- unrealized losses of $187 million during the three months ended September 30, 2012, which included a $121 million net decrease in the value of hedge and proprietary trading contracts for future periods and $66 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease in value was primarily related to increases in forward power and natural gas prices, partially offset by increases in forward coal prices; and

- unrealized gains of $38 million during the three months ended September 30, 2011, which included a $71 million net increase in the value of hedge and proprietary trading contracts for future periods offset by $33 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The increase in value was primarily related to decreases in forward power and natural gas prices.

Operating Expenses. Our operating expenses decrease of $104 million was principally a result of the following:

- $86 million decrease in impairment losses ($47 million recorded in 2012 relating to property, plant and equipment at two generating facilities compared to $133 million recorded in 2011 for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR); and

- $18 million decrease in operations and maintenance expense primarily related to the following:

- $22 million decrease in Mirant/RRI Merger-related costs, primarily for severance;

- $7 million decrease as a result of lower project and maintenance expenses; and

- $5 million decrease of major litigation costs, net of recoveries; partially offset by

- $8 million in costs to deactivate generating facilities, primarily for severance;

- $6 million resulting from changes in asset retirement obligation assumptions in 2011; and

- $5 million increase in NRG Merger-related costs.

Table of Contents

Adjusted Net Income and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted net income and adjusted EBITDA to net loss on a historical basis. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. The following compares actual results for the three months ended September 30, 2012 to the same period of 2011 and provides discussion of the changes.

	Three Months Ended September 30, 2012	2011
	(in millions)	
Net Loss	$ (85)	$ (40)
Unrealized (gains) losses	187	(38)
Impairment losses	47	133
Mirant/RRI Merger-related costs	2	24
NRG Merger-related costs	5	
Lower of cost or market inventory adjustments, net	(23)	(1)
Major litigation costs, net of recoveries		5
Costs to deactivate generating facilities	8	
Large scale remediation and settlement costs	(2)	
Other, net	2	(9)
Adjusted Net Income	141	74
Interest expense, net	85	85
Provision for income taxes	4	1
Depreciation and amortization	91	96
Adjusted EBITDA	$ 321	$ 256

Adjusted EBITDA was $321 million for the three months ended September 30, 2012 compared to $256 million for the same period of 2011. The increase was primarily related to higher contracted and capacity revenues in California and increased energy margin as a result of increased generation volumes from our gas-fired generating facilities.

Adjusted net income was $141 million for the three months ended September 30, 2012 compared to adjusted net income of $74 million for the same period of 2011. The increase in adjusted net income was primarily related to the same items that affected adjusted EBITDA.

Our net loss was $85 million for the three months ended September 30, 2012 compared to a net loss of $40 million for the same period of 2011. The increase in net loss was primarily a result of a decrease in unrealized gross margin, partially offset by a decrease in impairment losses and a decrease in Mirant/RRI Merger-related costs.

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. See note 10 to our interim financial statements for changes in our net generating capacity from 24,599 MW at January 1, 2011 to 22,670 MW at September 30, 2012.

Table of Contents

Gross Margin Overview

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

	Three Months Ended September 30, 2012 (in millions)					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
Energy	$ 74	$ 82	$ 13	$ 12	$ 14	$ 195
Contracted and capacity	74	64	176		27	341
Realized value of hedges	55	9	(2)		(2)	60
Total realized gross margin	203	155	187	12	39	596
Unrealized gross margin	(90)	(73)	2	(28)	2	(187)
Total gross margin(1)	$ 113	$ 82	$ 189	$ (16)	$ 41	$ 409

	Three Months Ended September 30, 2011 (in millions)					
	Eastern PJM	Western PJM/ MISO	California	Energy Marketing	Other Operations	Total
Energy	$ 64	$ 107	$ 6	$ 1	$ 7	$ 185
Contracted and capacity	65	77	109		23	274
Realized value of hedges	50	7	1		(1)	57
Total realized gross margin	179	191	116	1	29	516
Unrealized gross margin	(12)	36	1	16	(3)	38
Total gross margin(1)	$ 167	$ 227	$ 117	$ 17	$ 26	$ 554

(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, RMR arrangements, PPAs and tolling agreements, and 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.

Table of Contents

Operating Statistics

Our total margin capture factor was 95% and 92% during the three months ended September 30, 2012 and 2011, respectively. The following table summarizes power generation volumes by segment:

	Three Months Ended September 30, 2012	2011	Increase/ (Decrease)	Increase/ (Decrease)(1)
	(in gigawatt hours)			
Eastern PJM:				
Baseload	2,795	3,024	(229)	(8)%
Intermediate	838	478	360	75%
Peaking	76	62	14	23%
Total Eastern PJM	3,709	3,564	145	4%
Western PJM/MISO:				
Baseload	5,561	6,301	(740)	(12)%
Intermediate	6	3	3	100%
Peaking	116	55	61	111%
Total Western PJM/MISO	5,683	6,359	(676)	(11)%
California:				
Intermediate	915	204	711	NM
Peaking	1		1	NM
Total California	916	204	712	NM
Other Operations:				
Baseload	960	672	288	43%
Intermediate	282	162	120	74%
Peaking	211	214	(3)	(1)%
Total Other Operations	1,453	1,048	405	39%
Total	11,761	11,175	586	5%

(1) NM means not meaningful.

The total increase in power generation volumes during the three months ended September 30, 2012, as compared to the same period in 2011, is explained by segment below.

Eastern PJM. The net increase in generation volumes results from an increase in our intermediate and peaking generation volumes for gas-fired units primarily as a result of expanding spark spreads and a decrease in our baseload generation unplanned outages, partially offset by a decrease in our baseload generation volumes primarily as a result of contracting dark spreads for coal-fired units.

Western PJM/MISO. The net decrease in generation volumes results from a decrease in our baseload generation volumes for coal-fired units primarily as a result of contracting dark spreads, partially offset by an increase in generation from our gas-fired units primarily from expanding spark spreads.

California. The net increase in generation volumes results from an increase in our intermediate generation volumes primarily as a result of expanding spark spreads.

Other Operations. The net increase in generation volumes results from an increase in our baseload generation volumes primarily as a result of an increase in requested energy for units under a PPA and an increase in baseload and intermediate generation volumes for our facilities located in the Northeast as a result of reduced outages and expanding spark spreads.

Table of Contents

Eastern PJM

	Three Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 74	$ 64	$ 10
Contracted and capacity	74	65	9
Realized value of hedges	55	50	5
Total realized gross margin	203	179	24
Unrealized gross margin	(90)	(12)	(78)
Total gross margin (excluding depreciation and amortization)	113	167	(54)
Operating expenses:			
Operations and maintenance	101	99	2
Depreciation and amortization	34	34	
Impairment losses		95	(95)
Gain on sales of assets, net	(1)		(1)
Total operating expenses	134	228	(94)
Operating loss	$ (21)	$ (61)	$ 40

Gross Margin

The increase of $24 million in realized gross margin was principally a result of the following:

- $10 million increase in energy, primarily as a result of an increase in generation volumes for gas-fired units as a result of expanding spark spreads, partially offset by a decrease in generation volumes for coal-fired units as a result of contracting dark spreads;

- $9 million increase in contracted and capacity primarily as a result of higher capacity prices; and

- $5 million increase in realized value of hedges, primarily as a result of a $36 million increase in power hedges primarily resulting from lower prices, offset in part by a $31 million decrease in coal hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $90 million during the three months ended September 30, 2012, which included $51 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $39 million net decrease in the value of hedge contracts for future periods. The decrease in value was primarily related to increases in forward power and natural gas prices, partially offset by increases in forward coal prices; and

- unrealized losses of $12 million during the three months ended September 30, 2011, which included $41 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a $29 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices.

Table of Contents

Operating Expenses.

The decrease of $94 million in operating expenses was primarily the result of a $95 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011.

Western PJM/MISO

	Three Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 82	$ 107	$ (25)
Contracted and capacity	64	77	(13)
Realized value of hedges	9	7	2
Total realized gross margin	155	191	(36)
Unrealized gross margin	(73)	36	(109)
Total gross margin (excluding depreciation and amortization)	82	227	(145)
Operating expenses:			
Operations and maintenance	102	108	(6)
Depreciation and amortization	32	29	3
Impairment losses	47	4	43
Total operating expenses	181	141	40
Operating income (loss)	$ (99)	$ 86	$ (185)

Gross Margin

The decrease of $36 million in realized gross margin was principally a result of the following:

- $25 million decrease in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads; and

- $13 million decrease in contracted and capacity primarily as a result of lower capacity prices, partially offset by capacity payments received under our RMR arrangements in 2012, partially offset by

- $2 million increase in realized value of hedges, primarily as a result of a $28 million increase in power hedges primarily resulting from lower prices, offset in part by a $26 million decrease in coal and gas hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $73 million during the three months ended September 30, 2012, which included a $61 million net decrease in the value of hedge contracts for future periods and $12 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease in value was primarily related to increases in forward power and natural gas prices; and

- unrealized gains of $36 million during the three months ended September 30, 2011, which included a $31 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and $5 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Table of Contents

Operating Expenses

The increase of $40 million in operating expenses was primarily as a result of the following:

- $43 million increase in impairment losses ($47 million recorded in 2012 relating to property, plant and equipment at two generating facilities compared to $4 million recorded in 2011 for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR); partially offset by

- $6 million decrease in operations and maintenance expense related to lower project and maintenance expenses.

California

	Three Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 13	$ 6	$ 7
Contracted and capacity	176	109	67
Realized value of hedges	(2)	1	(3)
Total realized gross margin	187	116	71
Unrealized gross margin	2	1	1
Total gross margin (excluding depreciation and amortization)	189	117	72
Operating expenses:			
Operations and maintenance	34	33	1
Depreciation and amortization	10	11	(1)
Impairment losses		14	(14)
Gain on sales of assets, net		(5)	5
Total operating expenses	44	53	(9)
Operating income	$ 145	$ 64	$ 81

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. 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.

The increase of $67 million in contracted and capacity was primarily a result of higher capacity prices.

Operating Expenses.

The decrease of $9 million in operating expenses was primarily the result of a $14 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011.

Table of Contents

Energy Marketing

	Three Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 12	$ 1	$ 11
Total realized gross margin	12	1	11
Unrealized gross margin	(28)	16	(44)
Total gross margin (excluding depreciation and amortization)	(16)	17	(33)
Operating expenses:			
Operations and maintenance	1		1
Depreciation and amortization		1	(1)
Total operating expenses	1	1	
Operating income (loss)	$ (17)	$ 16	$ (33)

Gross Margin

The increase of $11 million in realized gross margin was primarily as a result of decreases in losses from fuel oil management activities.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $28 million during the three months ended September 30, 2012, which included a $24 million net decrease in the value of contracts for future periods and $4 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $16 million during the three months ended September 30, 2011, which included a $12 million net increase in the value of contracts for future periods and $4 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Other Operations

	Three Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 14	$ 7	$ 7
Contracted and capacity	27	23	4

Realized value of hedges	(2)	(1)	(1)
Total realized gross margin	39	29	10
Unrealized gross margin	2	(3)	5
Total gross margin (excluding depreciation and amortization)	41	26	15
Operating expenses:			
Operations and maintenance	30	46	(16)
Depreciation and amortization	15	21	(6)
Impairment losses		20	(20)
Gain (loss) on sales of assets, net		(1)	1
Total operating expenses	45	86	(41)
Operating loss	$ (4)	$ (60)	$ 56

Table of Contents

Gross Margin

The increase of $10 million in realized gross margin was principally a result of an increase of $7 million in energy primarily as a result of decreased fuel costs.

Operating Expenses

The decrease of $41 million in operating expenses was principally the result of the following:

- $20 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011; and

- $16 million decrease in operations and maintenance expense primarily related to a decrease of $22 million in Mirant/RRI Merger-related costs, primarily for severance, partially offset by an increase of $5 million in NRG Merger-related costs.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Consolidated Financial Performance

We reported a net loss of $345 million and $289 million during the nine months ended September 30, 2012 and 2011, respectively. The change in net loss is detailed as follows:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011 (in millions)	Increase/ (Decrease)
Realized gross margin	$ 1,296	$ 1,448	$ (152)
Unrealized gross margin	(229)	(59)	(170)
Total gross margin (excluding depreciation and amortization)	1,067	1,389	(322)
Operating expenses:			
Operations and maintenance	840	963	(123)
Depreciation and amortization	269	272	(3)
Impairment losses	47	133	(86)
Gain on sales of assets, net	(9)	(5)	(4)

Total operating expenses	1,147	1,363	(216)
Operating income (loss)	(80)	26	(106)
Other income (expense), net:			
Interest expense, net	(259)	(290)	(31)
Other, net	2	(21)	(23)
Total other expense, net	(257)	(311)	(54)
Loss before income taxes	(337)	(285)	(52)
Provision for income taxes	8	4	4
Net loss	$ (345)	$ (289)	$ (56)

Realized Gross Margin. Our realized gross margin decrease of $152 million was principally a result of the following:

• $262 million decrease in energy, primarily as a result of (a) a $208 million decrease primarily resulting from reduced generation volumes as a result of contracting dark spreads for our coal-fired units, partially offset by an increase in generation volumes for our gas-fired units as a result of expanding spark spreads, (b) a $34 million increase in lower of cost or market inventory adjustments, net and (c) a $40 million decrease in our Energy Marketing segment primarily as a result of decreases in income from proprietary trading and decreases in fuel oil management activities, partially offset by $20 million related to the

Table of Contents

advance settlement of an out-of-market contract obligation. This $20 million for the advance settlement of an out-of-market transmission contract relates to our successful permanent assignment of a long-term contract that was out-of-market and revalued as of the date of the Mirant/RRI Merger and recorded as a $20 million liability. We have no further obligations under this contract, do not need it to support our ongoing operations and therefore reversed the liability; and

- $24 million decrease in contracted and capacity primarily resulting from lower capacity prices in our Eastern PJM and Western PJM/MISO segments and the shutdown of the Potrero generating facility in our California segment in 2011; partially offset by

- $134 million increase in realized value of hedges, primarily as a result of a $238 million increase in power hedges primarily resulting from lower prices, offset in part by a $104 million decrease in coal and gas hedges resulting from lower prices.

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

- unrealized losses of $229 million during the nine months ended September 30, 2012, which included $292 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease was offset by a $63 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 decreases in forward coal prices; and

- unrealized losses of $59 million during the nine months ended September 30, 2011, which included $160 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $101 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 and increases in forward coal prices.

Operating Expenses. Our operating expenses decrease of $216 million was principally a result of the following:

- $123 million decrease in operations and maintenance expense primarily related to the following:

- $55 million decrease in Mirant/RRI Merger-related costs, primarily for severance;

- $35 million change in large scale remediation and settlement costs as we accrued $30 million for remediation costs at our Maryland ash facilities in 2011 and reversed $6 million in 2012;

- $33 million decrease primarily as a result of lower project, outage and maintenance expenses;

- $31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria;

- $12 million decrease from lower employee headcount and reduced rent expense as a result of completion of the Mirant/RRI Merger integration;

- $8 million decrease in major litigation costs, net of recoveries; partially offset by

- $46 million in costs to deactivate generating facilities (primarily for an inventory reserve for excess materials and supplies);

- $8 million reversal of Montgomery County Carbon levy assessment recorded in 2011; and

- $5 million increase in NRG Merger-related costs; and

Table of Contents

- $86 million decrease in impairment losses ($47 million recorded in 2012 relating to property, plant and equipment at two generating facilities compared to $133 million recorded in 2011 for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR).

Interest Expense, Net.

The decrease of $31 million was principally a result of a $25 million decrease related to lower interest expense as a result of the repayment in 2011 of GenOn Americas Generation senior unsecured notes and PEDFA bonds.

Other, Net.

The change of $23 million was principally a result of $23 million of other expense in 2011 relating to the loss on extinguishment of debt 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.

Adjusted Net Loss and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted net loss and adjusted EBITDA to net loss on a historical basis. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. The following compares actual results for the nine months ended September 30, 2012 to the same period of 2011 and provides discussion of the changes.

	Nine Months Ended September 30,	
	2012	**2011**
	(in millions)	
Net Loss	$ (345)	$ (289)
Unrealized losses	229	59
Impairment losses	47	133
Mirant/RRI Merger-related costs	6	61
NRG Merger-related costs	5	
Lower of cost or market inventory adjustments, net	21	(13)
Loss on early extinguishment of debt		23
Major litigation costs, net of recoveries	4	12
Reversal of Montgomery County carbon levy assessment for prior year		(8)
Advance settlement of out-of-market contract obligation	(20)	
Large scale remediation and settlement costs	(5)	30
Costs to deactivate generating facilities	46	
Reversal of Potomac River settlement obligation	(31)	
Other, net		(9)
Adjusted Net Loss	(43)	(1)
Interest expense, net	259	290
Provision for income taxes	8	4

Depreciation and amortization		269		272
Adjusted EBITDA	$	493	$	565

Table of Contents

Adjusted EBITDA was $493 million for the nine months ended September 30, 2012 compared to $565 million for the same period of 2011. The decline was primarily related to a reduction in energy gross margin as a result of reduced generation volumes and lower contracted and capacity revenues in Eastern PJM and Western PJM/MISO. The decline was partially offset by the increased realized value of hedges and lower adjusted operating and other expenses primarily from Mirant/RRI Merger cost savings.

Adjusted net loss was $43 million for the nine months ended September 30, 2012 compared to adjusted net loss of $1 million for the same period of 2011. The increase in adjusted net loss was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense, net.

Our net loss was $345 million for the nine months ended September 30, 2012 compared to a net loss of $289 million for the same period of 2011. The increase in net loss was primarily a result of a decrease in unrealized gross margin, costs incurred in 2012 to deactivate generating facilities and the same items that affected adjusted net loss. These increases were partially offset by a decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011, a loss on early extinguishment of debt in 2011 which was not repeated in 2012, a decrease in Mirant/RRI Merger-related costs, a decrease in large scale remediation and settlement costs, the advance settlement of an out-of-market contract obligation and the reversal of the Potomac River obligation under the 2008 agreement with the City of Alexandria.

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We have five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. See note 10 to our interim financial statements for changes in our net generating capacity from 24,599 MW at January 1, 2011 to 22,670 MW at September 30, 2012.

Gross Margin Overview

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

	Nine Months Ended September 30, 2012					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
	(in millions)					
Energy	$ 89	$ 106	$ 15	$ 36	$ 9	$ 255
Contracted and capacity	197	204	233		71	705
Realized value of hedges	271	68			(3)	336
Total realized gross margin	557	378	248	36	77	1,296
Unrealized gross margin	(161)	(56)	1	(16)	3	(229)
Total gross margin(1)	$ 396	$ 322	$ 249	$ 20	$ 80	$ 1,067

	Nine Months Ended September 30, 2011					
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Total
	(in millions)					
Energy	$ 175	$ 249	$ 10	$ 65	$ 18	$ 517
Contracted and capacity	239	246	173		71	729
Realized value of hedges	178	19	3		2	202
Total realized gross margin	592	514	186	65	91	1,448
Unrealized gross margin	(63)	10		5	(11)	(59)
Total gross margin(1)	$ 529	$ 524	$ 186	$ 70	$ 80	$ 1,389

(1) Gross margin excludes depreciation and amortization.

Table of Contents

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, RMR arrangements, PPAs and tolling agreements, and 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 94% and 91% during the nine months ended September 30, 2012 and 2011, respectively. The following table summarizes power generation volumes by segment:

[redacted]

Eastern PJM:				
Baseload	5,401	9,147	(3,746)	(41)%
Intermediate	2,429	744	1,685	NM
Peaking	131	114	17	15%
Total Eastern PJM	7,961	10,005	(2,044)	(20)%
Western PJM/MISO:				
Baseload	12,596	16,067	(3,471)	(22)%
Intermediate	14	1	13	NM
Peaking	135	81	54	67%
Total Western PJM/MISO	12,745	16,149	(3,404)	(21)%
California:				
Intermediate	1,087	330	757	NM
Peaking	3	2	1	50%
Total California	1,090	332	758	NM
Other Operations:				
Baseload	1,901	1,536	365	24%
Intermediate	317	248	69	28%
Peaking	375	314	61	19%

Total Other Operations	2,593	2,098	495	24%
Total	24,389	28,584	(4,195)	(15)%

(1) NM means not meaningful.

The total decrease in power generation volumes during the nine months ended September 30, 2012, as compared to the same period in 2011, is explained by segment below.

Eastern PJM. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads for coal-fired units, offset in part by an increase in our intermediate generation volumes for gas-fired units primarily as a result of expanding spark spreads, and a decrease in baseload generation unplanned outages.

Table of Contents

Western PJM/MISO. The net decrease in generation volumes results from a decrease in our baseload generation volumes primarily as a result of contracting dark spreads.

California. The net increase in generation volumes results from an increase in our intermediate generation volumes primarily as a result of expanding spark spreads.

Other Operations The net increase in generation volumes results from an increase in our baseload generation volumes primarily as a result of an increase in requested energy for units under a PPA and an increase in baseload and intermediate generation volumes for our facilities located in the Northeast as a result of reduced outages and expanding spark spreads.

Eastern PJM

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
		(in millions)	
Gross margin:			
Energy	$ 89	$ 175	$ (86)
Contracted and capacity	197	239	(42)
Realized value of hedges	271	178	93
Total realized gross margin	557	592	(35)
Unrealized gross margin	(161)	(63)	(98)
Total gross margin (excluding depreciation and amortization)	396	529	(133)
Operating expenses:			
Operations and maintenance	292	351	(59)
Depreciation and amortization	101	101	
Impairment losses		95	(95)
Gain on sales of assets, net	(1)		(1)
Total operating expenses	392	547	(155)
Operating income (loss)	$ 4	$ (18)	$ 22

Gross Margin

The decrease of $35 million in realized gross margin was principally a result of the following:

• $86 million decrease in energy, primarily as a result of (a) a $73 million decrease resulting from reduced generation volumes as a result of contracting dark spreads for our coal-fired units, partially offset by an increase in generation volumes for our gas-fired units as a result of expanding spark spreads and (b) a $13 million increase in lower of cost or market inventory adjustments, net; and

- $42 million decrease in contracted and capacity primarily as a result of lower capacity prices; partially offset by

- $93 million increase in realized value of hedges, primarily as a result of a $148 million increase in power hedges primarily resulting from lower prices, offset in part by a $55 million decrease in coal and gas hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $161 million during the nine months ended September 30, 2012, which included $225 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease was offset by a $64 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by decreases in coal prices; and

Table of Contents

- unrealized losses of $63 million during the nine months ended September 30, 2011, which included $155 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $92 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and increases in forward coal prices.

Operating Expenses.

The decrease of $155 million in operating expenses was principally a result of the following:

- $95 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011; and

- $59 million decrease in operations and maintenance expense primarily related to the following:

- $35 million change in large scale remediation and settlement costs as we accrued $30 million for remediation costs at our Maryland ash facilities in 2011 and reversed $6 million in 2012;

- $31 million reversal of the previously recorded Potomac River obligation under the 2008 agreement with the City of Alexandria; and

- $10 million decrease relating to decreased allocated corporate overhead costs primarily as a result of the completion of the Mirant/RRI Merger integration (including (i) the reduction in Mirant/RRI Merger-related costs and (ii) Merger cost savings);

- $8 million decrease in major litigation costs, net of recoveries; partially offset by

- $10 million in costs to deactivate generating facilities;

- $8 million reversal of Montgomery County Carbon levy assessment recorded in 2011; and

- $6 million resulting from changes in asset retirement obligation assumptions in 2011.

Western PJM/MISO

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
		(in millions)	
Gross margin:			
Energy	$ 106	$ 249	$ (143)
Contracted and capacity	204	246	(42)
Realized value of hedges	68	19	49
Total realized gross margin	378	514	(136)
Unrealized gross margin	(56)	10	(66)
Total gross margin (excluding depreciation and amortization)	322	524	(202)
Operating expenses:			
Operations and maintenance	346	368	(22)
Depreciation and amortization	93	88	5
Impairment losses	47	4	43
Gain on sales of assets, net	(1)		(1)
Total operating expenses	485	460	25
Operating income (loss)	$ (163)	$ 64	$ (227)

Table of Contents

Gross Margin

The decrease of $136 million in realized gross margin was principally a result of the following:

- $143 million decrease in energy, primarily as a result of (a) a $132 million decrease resulting from reduced generation volumes as a result of contracting dark spreads and (b) an $11 million increase in lower of cost or market inventory adjustments, net; and

- $42 million decrease in contracted and capacity primarily as a result of lower capacity prices, partially offset by capacity payments received under our RMR arrangements in 2012, partially offset by

- $49 million increase in realized value of hedges, primarily as a result of a $93 million increase in power hedges primarily resulting from lower prices, offset in part by a $44 million decrease in coal hedges resulting from lower prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $56 million during the nine months ended September 30, 2012, which included $65 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period. The decrease was offset by a $9 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by decreases in coal prices; and

- unrealized gains of $10 million during the nine months ended September 30, 2011, which included an $8 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices offset by the amortization of option premiums and $2 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $25 million in operating expenses was principally a result of the following:

- $43 million increase in impairment losses ($47 million recorded in 2012 relating to property, plant and equipment at two generating facilities compared to $4 million recorded in 2011 for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR); partially offset by

- $22 million decrease in operations and maintenance expense primarily related to the following:

- $39 million decrease primarily as a result of lower project, outage and maintenance expenses; and

- $9 million decrease relating to decreased allocated corporate overhead costs primarily as a result of the completion of the Mirant/RRI Merger integration (including (i) the reduction in Mirant/RRI Merger-related costs and (ii) Merger cost savings); partially offset by

- $30 million in costs to deactivate generating facilities (primarily for an inventory reserve for excess materials and supplies).

Table of Contents

California

	Nine Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 15	$ 10	$ 5
Contracted and capacity	233	173	60
Realized value of hedges		3	(3)
Total realized gross margin	248	186	62
Unrealized gross margin	1		1
Total gross margin (excluding depreciation and amortization)	249	186	63
Operating expenses:			
Operations and maintenance	117	111	6
Depreciation and amortization	33	32	1
Impairment losses		14	(14)
Gain on sales of assets, net		(5)	5
Total operating expenses	150	152	(2)
Operating income	$ 99	$ 34	$ 65

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, and our Potrero units were subject to RMR arrangements through February 2011. 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 arrangements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

The increase of $60 million in contracted and capacity was primarily a result of higher capacity prices.

Operating Expenses.

The decrease of $2 million in operating expenses was primarily a result of $14 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011, partially offset by $6 million increase in operations and maintenance expense related to increased project, outage and maintenance expenses.

62

Table of Contents

Energy Marketing

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
		(in millions)	
Gross margin:			
Energy	$ 36	$ 65	$ (29)
Total realized gross margin	36	65	(29)
Unrealized gross margin	(16)	5	(21)
Total gross margin (excluding depreciation and amortization)	20	70	(50)
Operating expenses:			
Operations and maintenance	4	2	2
Depreciation and amortization		2	(2)
Total operating expenses	4	4	
Operating income	$ 16	$ 66	$ (50)

Gross Margin

The decrease of $29 million in realized gross margin was primarily as a result of a $49 million decrease in income from proprietary trading and decreases in fuel oil management activities, partially offset by $20 million related to the advance settlement of an out-of-market contract obligation.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $16 million during the nine months ended September 30, 2012, which included a $14 million net decrease in the value of contracts for future periods and $2 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $5 million during the nine months ended September 30, 2011, which included a $3 million net increase in the value of contracts for future periods and $2 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Table of Contents

Other Operations

	Nine Months Ended September 30, 2012	2011 (in millions)	Increase/ (Decrease)
Gross margin:			
Energy	$ 9	$ 18	$ (9)
Contracted and capacity	71	71	
Realized value of hedges	(3)	2	(5)
Total realized gross margin	77	91	(14)
Unrealized gross margin	3	(11)	14
Total gross margin (excluding depreciation and amortization)	80	80	
Operating expenses:			
Operations and maintenance	81	131	(50)
Depreciation and amortization	42	49	(7)
Impairment losses		20	(20)
Gain on sales of assets, net	(7)		(7)
Total operating expenses	116	200	(84)
Operating loss	$ (36)	$ (120)	$ 84

Gross Margin

The decrease of $14 million in realized gross margin was principally a result of a decrease of $9 million in energy, primarily as a result of decreases in prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $3 million during the nine months ended September 30, 2012, associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and

- unrealized losses of $11 million during the nine months ended September 30, 2011, which included $7 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $4 million net decrease in the value of hedge contracts for future periods.

Operating Expenses

The decrease of $84 million in operating expenses was principally the result of the following:

- $50 million decrease in operations and maintenance expense primarily related to a decrease of $55 million in Mirant/RRI Merger-related costs, primarily for severance, partially offset by an increase of $5 million in NRG Merger-related costs;

- $20 million decrease in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR recorded in 2011; and

- $7 million increase in gain on sales of assets primarily as a result of the sale of our Indian River generating facility in January 2012.

Table of Contents

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 5 to our interim financial statements for additional discussion of our debt.

Sources of Funds and Capital Structure

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).

The table below sets forth total available cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at September 30, 2012 (in millions):

Cash and Cash Equivalents:		
GenOn (excluding GenOn Mid-Atlantic and REMA)	$	1,665
GenOn Mid-Atlantic		171
REMA(1)		19
Total cash and cash equivalents(2)		1,855
Availability under GenOn credit facilities(3)		560
Total available cash, cash equivalents and availability under GenOn credit facilities(2)(3)	$	2,415

(1) At September 30, 2012, REMA did not satisfy the restricted payments test and therefore could not use such funds to distribute cash and make other restricted payments.

(2) We have $170 million of collateral deposits from counterparties (including brokers), which are included in accounts payable and accrued liabilities.

(3) 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 September 30, 2012, except for amounts held in bank accounts to cover upcoming payables, all of our cash and cash equivalents were invested in AAA-rated United States Treasury money market funds and treasury bills.

Table of Contents

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, LLC 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 September 30, 2012, the present values of lease payments under the GenOn Mid-Atlantic and REMA operating leases were $846 million and $440 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 $1.2 billion and $712 million, respectively.

(3) At September 30, 2012, $109 million and $241 million were outstanding under the GenOn Marsh Landing senior secured term loan, due 2017 and senior secured term loan, due 2023, respectively.

Table of Contents

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 payments tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At September 30, 2012, GenOn Mid-Atlantic satisfied the restricted payments test. At September 30, 2012, REMA did not satisfy the restricted payments test.

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.

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 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 estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the period October 1, 2012 through December 31, 2013 will be $503 million. See Capital Expenditures and Capital Resources for further discussion of our capital expenditures.

Cash Collateral and Letters of Credit. 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 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, equipment purchases and other operating activities. Credit support includes cash collateral, letters of credit, surety bonds and financial guarantees. In the event that we default, the counterparty is permitted to draw on a letter of credit or surety bond or apply cash collateral held to satisfy the existing amounts outstanding under an open contract. Our requirements for collateral and, accordingly, liquidity 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.

At September 30, 2012, we had $209 million of posted cash collateral and $228 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 $80 million of cash-collateralized letters of credit in support of the Marsh Landing project and delivered $48 million of surety bonds to satisfy various other credit support agreements.

Table of Contents

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

	September 30, 2012	December 31, 2011
	(in millions)	
Cash collateral posted energy trading and marketing	$ 150	$ 185
Cash collateral posted other operating activities	59	39
Letters of credit rent reserves	107	130
Letters of credit Marsh Landing project(1)	129	175
Letters of credit energy trading and marketing	59	59
Letters of credit other operating activities	13	32
Surety bonds(2)	48	46
Total	$ 565	$ 666

(1) Includes $80 million and $131 million of cash-collateralized letters of credit at September 30, 2012 and December 31, 2011, respectively.

(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at September 30, 2012 and December 31, 2011.

Restricted Payments Limitations. The GenOn credit agreement and indenture for the senior notes due 2018 and 2020 restrict the ability of GenOn to make restricted payments, including dividends and purchases of capital stock. At September 30, 2012, GenOn did not meet the consolidated debt ratio component of the restricted payments test in the indenture and, therefore, the ability of GenOn to make restricted payments is limited to specified exclusions from the covenant, including up to $250 million of such restricted payments.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

There have been no material changes outside the ordinary course of business to our debt obligations, off-balance sheet arrangements and contractual obligations from those disclosed in our 2011 Annual Report on Form 10-K and note 5 to our interim financial statements.

Historical Cash Flows

	Nine Months Ended September 30, 2012	2011	Increase/ (Decrease)
		(in millions)	
Net cash provided by operating activities	$ 266	$ 282	$ (16)
Net cash provided by (used in) investing activities	(314)	1,086	(1,400)
Net cash provided by (used in) financing activities	235	(2,024)	2,259

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 before changes in operating assets and liabilities increased $25 million for the nine months ended September 30, 2012, compared to the same period in 2011, primarily resulting from a decrease in net loss, adjusted for non-cash items, in 2012. Changes in our cash flows from operating activities before changes in operating assets and liabilities were generally consistent with changes in our results of operations, adjusted for non-cash items. See Results of Operations for additional information related to our performance in 2012 as compared to the same period in 2011.

Cash provided by changes in operating assets and liabilities decreased by $41 million primarily as a result of the following:

- *Net receivables and accounts payable and accrued liabilities.* A decrease in cash provided of $40 million primarily as a result of a decrease in receivables in 2011 partially offset by a higher volume of settlements of power hedges in 2011 as compared to the same period in 2012;

Table of Contents

- *Inventories.* An increase in cash used of $34 million primarily related to changes in fuel oil and coal inventory and purchased emissions allowances;

- *Income taxes*. An increase in cash used of $18 million primarily as a result of income tax payments, settlements and refunds;

- *Taxes other than income taxes*. An increase in cash used of $19 million primarily as a result of property tax payments; and

- *Other operating assets and liabilities*. A decrease in cash provided of $33 million related to changes in other operating assets and liabilities.

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

- *Funds on deposit.* An increase in cash provided of $62 million primarily as a result of $66 million of collateral returned from our counterparties in 2012 compared to $4 million of collateral returned from our counterparties in 2011; and

- *Accounts payable, collateral.* An increase in cash provided of $41 million as a result of $41 million posted by our counterparties in 2012 compared to less than $1 million posted by our counterparties in 2011 primarily resulting from a contract modification in April 2012 to require a counterparty to post cash collateral to secure credit exposure above an agreed threshold as a result of changes in power or natural gas prices.

Investing Activities. Net cash provided by/used in investing activities changed by $1.4 billion for the nine months ended September 30, 2012, compared to the same period in 2011. This difference was primarily a result of the following:

- *Restricted funds on deposit debt financing*. A decrease in cash provided of $1.545 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 and withdrawn to repay long-term debt during 2011; and

- *Capital expenditures.* An increase in cash used of $158 million primarily related to a $107.1 million payment in connection with the scrubber contract litigation settlement in 2012 and construction of our Marsh Landing generating facility, partially offset by a $68 million payment related to the Maryland scrubber projects in 2011; partially offset by

• *Restricted funds on deposit liens under scrubber contract litigation.* A change in cash of $331 million related to $165.6 million of funds placed in restricted deposits in 2011 as a result of the scrubber contract litigation and related liens and $165.6 million of those same liens released in 2012 in connection with the settlement.

Financing Activities. Net cash provided by/used in financing activities changed by $2.259 billion for the nine months ended September 30, 2012, compared to the same period in 2011. This difference was primarily a result of the following:

• *Repayment of long-term debt.* A decrease in cash used of $2.067 billion primarily related to repayment during 2011 of GenOn senior secured notes, GenOn Americas Generation senior unsecured notes, GenOn North America senior unsecured notes and PEDFA bonds; and

• *Proceeds from long-term debt.* An increase in cash provided of $193 million related to proceeds received to finance the construction of our Marsh Landing generating facility.

Table of Contents

Critical Accounting Estimates

See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates, in Item 7 in our 2011 Annual Report on Form 10-K.

Recently Adopted Accounting Guidance

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2011 Annual Report on Form 10-K and notes 1 and 4 to our interim financial statements.

Fair Value Measurements

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 the nine months ended September 30, 2012 and 2011:

	Commodity Contracts		Other Contracts	
	Asset Management	Trading	Interest Rate	Total
	(in millions)			
Fair value of portfolio of assets and liabilities at January 1, 2012	$ 916	$ (3)	$ (32)	$ 881
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value(1)	62	8	(19)	51
Purchases(2)				
Issuances(2)				
Settlements(3)	(288)	(3)	1	(290)
Fair value of portfolio of assets and liabilities at September 30, 2012	$ 690	$ 2	$ (50)	$ 642
Fair value of portfolio of assets and liabilities at January 1, 2011	$			