GenOn Energy, Inc.
Form 10-Q
August 08, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from to

Commission File Number: 1-16455

GenOn Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0655566**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**
1000 Main Street, Houston, Texas	**77002**
(Address of Principal Executive Offices)	**(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. þ Yes ¨ 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). þ Yes ¨ 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 þ	Accelerated Filer ¨
Non-accelerated Filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

As of August 1, 2011, there were 771,676,980 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

AB 32	California s Global Warming Solutions Act.
ancillary services	Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation service, spinning and non-spinning reserves and voltage support.
Bankruptcy Court	United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.
baseload generating units	Units designed to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously.
CAIR	Clean Air Interstate Rule.
CAISO	California Independent System Operator.
CAMR	Clean Air Mercury Rule.
capacity	Energy that could have been generated at continuous full-power operation during the period.
CARB	California Air Resources Board.
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002.
CFTC	Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
CO_2	Carbon dioxide.
CSAPR	Cross-State Air Pollution Rule.
dark spread	The difference between power prices and coal fuel costs.
D.C. Circuit	The United States Court of Appeals for the District of Columbia Circuit.
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.
Exchange Ratio	Right of Mirant Corporation stockholders to receive 2.835 shares of common stock of RRI Energy, Inc. in the Merger.
FASB	Financial Accounting Standards Board.
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 Merger.
GenOn Americas	GenOn Americas, Inc. (formerly known as Mirant Americas, Inc.).
GenOn Americas Generation	GenOn Americas Generation, LLC (formerly known as Mirant 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 Energy Management	GenOn Energy Management, LLC (formerly known as Mirant Energy Trading, LLC).
GenOn Lovett	GenOn Lovett, LLC, owner of the former Lovett generating facility, which was shut down on April 19, 2008, and has been demolished (formerly known as Mirant Lovett, LLC).
GenOn Marsh Landing	GenOn Marsh Landing, LLC (formerly known as Mirant Marsh Landing, LLC).
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC (formerly known as Mirant Mid-Atlantic, LLC) and, except where the context indicates otherwise, its subsidiaries.
GenOn North America	GenOn North America, LLC (formerly known as Mirant North America, LLC).
HAP	Hazardous Air Pollutant.
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.
ISO	Independent system operator.
ISO-NE	Independent System Operator-New England.
LIBOR	London InterBank Offered Rate.
MACT	Maximum achievable control technology.
MC Asset Recovery	MC Asset Recovery, LLC.
MDE	Maryland Department of the Environment.
Merger	The merger completed on December 3, 2010 pursuant to the Merger Agreement.
Merger Agreement	The agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
MISO	Midwest Independent Transmission System Operator.
MW	Megawatt.
MWh	Megawatt hour.
NAAQS	National Ambient Air Quality Standards.
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.

Table of Contents

NPDES	National pollutant discharge elimination system.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
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.
PEDFA	Pennsylvania Economic Development Financing Authority.
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.
REMA	GenOn REMA, LLC and its subsidiaries (formerly known as RRI Energy Mid-Atlantic Power Holdings, LLC).
RGGI	Regional Greenhouse Gas Initiative.
RMR	Reliability-must-run.
RPM	Model utilized by PJM to meet load serving entities forecasted capacity obligations through a forward-looking commitment of capacity resources.
RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Merger.
RTO	Regional Transmission Organization.
SCR	Selective catalytic reduction emissions controls.
scrubbers	Flue gas desulfurization emissions controls.
SEC	United States Securities and Exchange Commission.
Securities Act	Securities Act of 1933, as amended.
Series A Warrants	Warrants issued by Mirant on January 3, 2006, with an exercise price of $21.87 and expiration date of January 3, 2011.
Series B Warrants	Warrants issued by Mirant on January 3, 2006, with an exercise price of $20.54 and expiration date of January 3, 2011.
SO_2	Sulfur dioxide.
Stone & Webster	Stone & Webster, Inc.
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.
Virginia DEQ	Virginia Department of Environmental Quality.
WCI	Western Climate Initiative.

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-Q 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 terminology such as may, will, should, could, objective, projection, forecast, goal, guidance, outlook, expect, intend, seek, plan, predict, target, potential or continue or the negative of these terms or other comparable terminology.

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:

- our ability to integrate successfully the businesses following the Merger or realize cost savings and any other synergies as a result of the Merger;
- 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 supply and delivery of fuel for our generating facilities, at our required specifications and on terms and prices acceptable to us;
- failure to obtain adequate fuel supply, including from curtailments of the transportation of fuel;
- 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;
- deterioration in the financial condition of our 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;
- the failure of our generating facilities to perform as expected, including outages for unscheduled maintenance or repair;
- hazards customary to the power generation industry 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 failure to utilize new, or advancements in, 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;

the cost and availability of emissions allowances;

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

our ability to execute our business plan in California, including entering into new arrangements for sales of capacity, energy and other products from our existing generating facilities;

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;

Table of Contents

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

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

war, terrorist activities, cyberterrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss;

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;

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 asset management, proprietary trading and fuel oil management activities as expected, or may result in material gains or 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 asset management, proprietary trading and fuel oil management activities and volatility in our cash flow from operations resulting from working capital requirements, including collateral, to support our asset management, proprietary trading and fuel oil management activities;

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, environmental and other laws and regulations to which we and our subsidiaries and affiliates are or could become subject;

more stringent 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;

increased regulation that limits our access to adequate water supplies and landfill options needed to support power generation or that increases the costs of cooling water and handling, transporting and disposing of ash and other byproducts;

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 disposition of pending or threatened litigation, including environmental litigation;

Table of Contents

- the inability of our operating subsidiaries to generate sufficient cash to support our operations;
- the ability of lenders under our revolving 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 to comply with provisions of our operating leases, loan agreements and debt may lead to a breach and, if not remedied, result in an event of default thereunder, which could result in such lessors, lenders and debt holders exercising remedies, limit access to needed liquidity and damage our reputation and relationships with financial institutions;
- covenants contained in our credit facilities, debt and leases that restrict our current and future operations, particularly our ability to respond to changes or take certain actions that may be in our long-term best interests; and
- our ability to borrow additional funds and access capital markets.

Many of these risks, uncertainties and assumptions are beyond our ability to control or predict. All forward-looking statements contained herein are expressly qualified in their entirety by cautionary statements contained throughout this report. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Furthermore, forward-looking statements speak only as of the date they are made.

We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report. Our filings and other important information are also available on our investor relations page at www.genon.com/investors.aspx.

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 2010 Annual Report on Form 10-K.

Certain Terms

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

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 June 30, 2011 (September 30,)	Three Months Ended June 30, 2010 (September 30,)	Six Months Ended June 30, 2011 (September 30,)	Six Months Ended June 30, 2010 (September 30,)
	(in millions, except per share data)			
	(See notes 1 and 2 on the Merger)			
Operating revenues (including unrealized gains (losses) of $(36) million, $(231) million, $(135) million and $132 million, respectively)	$ 812	$ 244	$ 1,626	$ 1,124
Cost of fuel, electricity and other products (including unrealized (gains) losses of $(18) million, $109 million, $(38) million and $120 million, respectively)	393	272	797	479
Gross Margin (excluding depreciation and amortization)	419	(28)	829	645
Operating Expenses:				
Operations and maintenance	371	132	675	298
Depreciation and amortization	88	53	174	104
(Gain) loss on sales of assets, net	2	(1)	1	(3)
Total operating expenses	461	184	850	399
Operating Income (Loss)	(42)	(212)	(21)	246
Other Income (Expense), net:				
Interest expense	(96)	(49)	(205)	(99)
Other, net		(1)	(22)	(2)
Total other expense, net	(96)	(50)	(227)	(101)
Income (Loss) Before Income Taxes	(138)	(262)	(248)	145
Provision for income taxes		1	3	1
Net Income (Loss)	$ (138)	$ (263)	$ (251)	$ 144
Basic and Diluted EPS:				
Basic EPS	$ (0.18)	$ (0.64)	$ (0.33)	$ 0.35
Diluted EPS	$ (0.18)	$ (0.64)	$ (0.33)	$ 0.35
Weighted average shares outstanding	772	412	771	412

Effect of dilutive securities				1
Weighted average shares outstanding assuming dilution	772	412	771	413

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 BALANCE SHEETS (UNAUDITED)

	September 30, June 30, 2011	September 30, December 31, 2010
	(in millions)	
	(See notes 1 and 2 on the Merger)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,602	$ 2,402
Funds on deposit	477	1,834
Receivables, net	382	536
Derivative contract assets	847	1,420
Inventories	525	554
Prepaid expenses and other current assets	120	155
Total current assets	3,953	6,901
Property, plant and equipment, gross	7,408	7,275
Accumulated depreciation and amortization	(1,101)	(977)
Property, Plant and Equipment, net	6,307	6,298
Noncurrent Assets:		
Intangible assets, net	133	144
Derivative contract assets	577	716
Deferred income taxes	469	362
Prepaid rent	398	348
Other	525	505
Total noncurrent assets	2,102	2,075
Total Assets	$ 12,362	$ 15,274
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 6	$ 2,058
Accounts payable and accrued liabilities	765	902
Derivative contract liabilities	720	1,227
Deferred income taxes	469	362
Other	130	133
Total current liabilities	2,090	4,682
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,029	4,023
Derivative contract liabilities	95	189
Pension and postretirement obligations	171	171
Other	613	592
Total noncurrent liabilities	4,908	4,975

Commitments and Contingencies				
Stockholders Equity:				
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at June 30, 2011 and December 31, 2010				
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 771,634,656 shares and 770,857,530 shares at June 30, 2011 and December 31, 2010, respectively		1		1
Additional paid-in capital		7,442		7,432
Accumulated deficit		(2,042)		(1,791)
Accumulated other comprehensive loss		(37)		(25)
Total stockholders equity		5,364		5,617
Total Liabilities and Stockholders Equity	$	12,362	$	15,274

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

2

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(UNAUDITED)

	September 30, Common Stock	September 30, Additional Paid-In Capital	September 30, Accumulated Deficit	September 30, Accumulated Other Comprehensive Loss	September 30, Total Stockholders Equity
			(in millions)		
			(See notes 1 and 2 on the Merger)		
Balance, December 31, 2010	$ 1	$ 7,432	$ (1,791)	$ (25)	$ 5,617
Stock-based compensation		8			8
Exercise of stock options		2			2
Net loss			(251)		(251)
Other comprehensive loss				(12)	(12)
Total comprehensive loss					(263)
Balance, June 30, 2011	$ 1	$ 7,442	$ (2,042)	$ (37)	$ 5,364

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

3

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	September 30, 2011	September 30, 2010
	Six Months Ended June 30, (in millions)	
	(See notes 1 and 2 on the Merger)	
Cash Flows from Operating Activities:		
Net income (loss)	$ (251)	$ 144
Adjustments to reconcile net income (loss) and changes in other operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	181	106
Amortization of acquired contracts	(15)	
(Gain) loss on sales of assets, net	1	(3)
Net changes in derivative contracts	97	(12)
Stock-based compensation expense	8	8
Postretirement benefits curtailment gain		(37)
Lower of cost or market inventory adjustments	1	20
Loss on early extinguishment of debt.	23	
Other, net		(3)
Funds on deposit	(99)	6
Changes in other operating assets and liabilities	69	(79)
Total adjustments	266	6
Net cash provided by operating activities of continuing operations	15	150
Net cash provided by operating activities of discontinued operations		4
Net cash provided by operating activities	15	154
Cash Flows from Investing Activities:		
Capital expenditures	(183)	(160)
Proceeds from the sales of assets	12	3
Restricted funds on deposit, net	1,418	(31)
Net cash provided by (used in) investing activities	1,247	(188)
Cash Flows from Financing Activities:		
Repayment of long-term debt	(2,072)	(69)
Proceeds from long-term debt	9	
Other, net	1	(1)
Net cash used in financing activities	(2,062)	(70)
Net Decrease in Cash and Cash Equivalents	(800)	(104)
Cash and Cash Equivalents, beginning of period	2,402	1,953
Cash and Cash Equivalents, end of period	$ 1,602	$ 1,849

Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	$ 213	$ 92
Cash paid for income taxes (net of refunds received)	$ (6)	$ 2

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

4

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 provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through ownership and operation of, and contracting for, power generation capacity. We are a wholesale generator with approximately 24,200 MW of net electric generating capacity in the PJM, MISO, Northeast and Southeast regions, and California. We also operate integrated asset management and energy marketing organizations, including proprietary trading operations.

We were formed as a Delaware corporation in August 2000. GenOn changed its name from RRI Energy, Inc. effective December 3, 2010 in connection with the Merger. We, us, our and GenOn refer to GenOn Energy, Inc. and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed the Merger. See note 2 for additional information on the Merger.

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 2010 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.

In connection with the Merger, former Mirant stockholders received approximately 54% of the voting interest in the combined company. Although RRI Energy was the legal acquirer, the Merger is accounted for as a reverse acquisition whereby Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the interim financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the interim financial statements and other financial information of Mirant.

At June 30, 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 12 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 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 assets acquired and liabilities assumed in connection with the Merger;
- estimating the fair value of certain derivative contracts;

estimating future taxable income in evaluating the deferred tax asset valuation allowance;

Table of Contents

- 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.

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, June 30, 2011	September 30, December 31, 2010
	(in millions)	
Cash collateral posted[(1)]	$ 360	$ 299
GenOn Marsh Landing development project cash collateral posted[(2)]	146	106
GenOn Mid-Atlantic restricted cash[(3)]	143	
Environmental compliance deposits[(4)]	33	32
Funds deposited with the trustee to discharge the GenOn senior secured notes, due 2014[(5)]		285
Funds deposited with the trustee to defease the PEDFA fixed-rate bonds, due 2036[(5)]		394
Funds deposited with the trustee to discharge the GenOn North America senior notes, due 2013[(5)]		866
Other	21	40
Total current and noncurrent funds on deposit	703	2,022
Less: Current funds on deposit	477	1,834
Total noncurrent funds on deposit	$ 226	$ 188

(1) Represents cash collateral posted for energy trading and marketing and other operating activities; includes $32 million related to the Potomac River Settlement (see note 19 to our consolidated financial statements in our 2010 Annual Report on Form 10-K); includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at June 30, 2011 and December 31, 2010.

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

(3) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation. See note 12.

(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 under the Industrial Site Recovery Act. See note 12 for our obligations related to ash landfill sites and site contamination remediation.

(5) See note 6 for discussion of the related debt.

6

Table of Contents

Inventories

Inventories were comprised of the following:

	September 30, June 30, 2011	September 30, December 31, 2010
	(in millions)	
Fuel inventory:		
Coal	$ 198	$ 153
Fuel oil	95	170
Natural gas		1
Other	5	1
Materials and supplies	196	194
Purchased emissions allowances	31	35
Total inventories	$ 525	$ 554

During the three months ended June 30, 2011 and 2010, we recorded $1 million and $12 million, respectively, and during the six months ended June 30, 2011 and 2010, we recorded $1 million and $20 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

Capitalization of Interest Cost

We incurred the following interest costs:

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Six Months Ended June 30, 2011	September 30, 2010
	(in millions)			
Total interest costs	$ 99	$ 50	$ 210	$ 102
Capitalized and included in property, plant and equipment, net	(3)	(1)	(5)	(3)
Interest expense	$ 96	$ 49	$ 205	$ 99

The amounts of capitalized interest above include interest accrued. During the three months ended June 30, 2011 and 2010, cash paid for interest was $201 million and $93 million, respectively, of which $4 million and $3 million, respectively, were capitalized. During the six months ended June 30, 2011 and 2010, cash paid for interest was $218 million and $95 million, respectively, of which $5 million and $3 million, respectively, were capitalized.

Income Taxes

At June 30, 2011, our deferred tax assets, as reduced by the valuation allowance, are completely offset by our deferred tax liabilities. Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. We have evaluated the evidence at June 30, 2011 and based on our judgment have determined that it is more-likely-than-not (greater than a 50% probability) that the net deferred tax assets will not be realized.

Recently Adopted Accounting Guidance

We adopted FASB accounting guidance for the quarter ended March 31, 2011 that requires a reconciliation for Level 3 fair value measurements, including presenting separately the amounts of purchases, issuances and settlements on a gross basis. See note 5 for additional information on fair value measurements.

Table of Contents

New Accounting Guidance Not Yet Adopted at June 30, 2011

In May 2011, the FASB issued new fair value measurement and disclosure guidance. The new standard does not extend the use of fair value but rather provides guidance about how fair value should be determined and requires additional disclosures. The guidance is not expected to have a material effect on our fair value measurements, but will require 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.

We will present the additional disclosures as required in our Form 10-Q for the quarter ended March 31, 2012.

In June 2011, the FASB issued guidance that revises the manner in which companies present comprehensive income in their financial statements. The guidance 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. We will update our presentation as required in our Form 10-Q for the quarter ended March 31, 2012.

2. Merger

On December 3, 2010, Mirant and RRI Energy completed the Merger. The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, we have conducted an assessment of the net assets acquired and recognized provisional amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred. The initial accounting for the business combination is not complete because the valuations necessary to assess the fair values of certain net assets acquired and contingent liabilities assumed are still in process. The significant assets and liabilities for which provisional amounts are recognized at June 30, 2011 and December 31, 2010 are property, plant and equipment, intangible assets and long-term liabilities related to out-of-market contracts, contingencies, taxes and asset retirement obligations. The provisional amounts recognized are subject to revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments will affect the gain on bargain purchase and material changes could require the financial statements to be retroactively amended. The allocation of the purchase price may be modified up to one year from the date of the Merger, as more information is obtained about the fair value of assets acquired and liabilities assumed. We will finalize these amounts during 2011.

3. Merger-Related Costs

Changes in merger-related costs (recorded in operations and maintenance expense in the Other Operations segment) are as follows (in millions):

	September 30,
Balance, January 1, 2011	$ 30(1)
Accrued and expensed	37(2)
Paid	(45)
Balance, June 30, 2011	$ 22(1)

(1) Included in accounts payable and accrued liabilities in the applicable consolidated balance sheet.
(2) Includes $26 million of charges associated with employee severance and $11 million of charges related to integration and other activities.

Table of Contents

4. Comprehensive Income (Loss)

The components of comprehensive income (loss) are:

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Six Months Ended June 30, 2011	September 30, 2010
	(in millions)			
Net income (loss)	$ (138)	$ (263)	$ (251)	$ 144
Pension and other postretirement benefits		7		5
Deferred loss from cash flow hedges	(14)		(11)	
Unrealized losses on available-for-sale securities			(1)	
Total comprehensive income (loss)	$ (152)	$ (256)	$ (263)	$ 149

5. 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 three million barrels of storage capacity that we own or lease, 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.

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.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge. In the fourth quarter of 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 six months ended June 30, 2011 or during 2010.

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 the ineffective portion of changes in fair value of cash flow hedges immediately into earnings.

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

Table of Contents

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.

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

	September 30,	September 30,	September 30,	September 30,	September 30,
	Derivative Contract Assets		Derivative Contract Liabilities		Net Derivative Contract
	Current	Long-Term	Current	Long-Term	Assets (Liabilities)
			(in millions)		
June 30, 2011					
Commodity Contracts:					
Asset management	$ 394	$ 540	$ (252)	$ (67)	$ 615
Trading activities	453	28	(467)	(28)	(14)
Total commodity contracts	847	568	(719)	(95)	601
Interest Rate Contracts		9	(1)		8
Total derivatives	$ 847	$ 577	$ (720)	$ (95)	$ 609
December 31, 2010					
Commodity Contracts:					
Asset management	$ 564	$ 627	$ (368)	$ (117)	$ 706
Trading activities	856	70	(859)	(72)	(5)
Total commodity contracts	1,420	697	(1,227)	(189)	701
Interest Rate Contracts		19			19
Total derivatives	$ 1,420	$ 716	$ (1,227)	$ (189)	$ 720

Table of Contents

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

	September 30,	September 30,	September 30,	September 30,
	Three Months Ended June 30,			
	2011		2010	
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	$ (48)	$ 18	$ (218)	$ (109)
Realized[(1)(2)]	61	(14)	91	(11)
Total asset management	$ 13	$ 4	$ (127)	$ (120)
Trading Commodity Contracts:				
Unrealized	$ 12	$	$ (13)	$
Realized[(1)(2)]	(1)		(21)	
Total trading	$ 11	$	$ (34)	$
Total derivatives	$ 24	$ 4	$ (161)	$ (120)

(1) Represents the total cash settlements of derivative financial instruments during each quarterly reporting period that existed at the beginning of each respective period.
(2) Effective January 1, 2011, excludes settlement value of fuel contracts classified as inventory.

	September 30,	September 30,	September 30,	September 30,
	Six Months Ended June 30,			
	2011		2010	
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	$ (123)	$ 38	$ 135	$ (120)
Realized[(1)(2)]	140	(57)	176	(26)
Total asset management	$ 17	$ (19)	$ 311	$ (146)
Trading Commodity Contracts:				
Unrealized	$ (12)	$	$ (3)	$
Realized[(1)(2)]	5		(2)	
Total trading	$ (7)	$	$ (5)	$
Total derivatives	$ 10	$ (19)	$ 306	$ (146)

(1) Represents the total cash settlements of derivative financial instruments during each quarterly reporting period that existed at the beginning of each respective period.
(2) Effective January 1, 2011, excludes settlement value of fuel contracts classified as inventory.

Table of Contents

The following table presents the effect of the interest rate swaps designated as cash flow hedges in the unaudited consolidated statements of stockholders equity and comprehensive income/loss during the three and six months ended June 30, 2011 (amount of gain (loss)):

Recognized in OCI on Interest Rate Derivatives	September 30, Location of Gain (Loss) Recognized in Income/Loss	September 30, Reclassified from Accumulated OCI into Earnings (in millions)	September 30, Recognized in Earnings on Derivatives(1)(2)
Three Months Ended June 30, 2011:			
$(14)	Interest expense	$	$
Six Months Ended June 30, 2011:			
$(11)	Interest expense	$	$

(1) Represents the ineffective portion of the interest rate swaps classified as cash flow hedges. The assessment of effectiveness excludes the default risk of the counterparties to these transactions and our own non-performance risk. The effect of these valuation adjustments was a loss of an immaterial amount during the three and six months ended June 30, 2011 and was 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.

At June 30, 2011, 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 12 years. At June 30, 2011, the accumulated OCI balance was $10 million. 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.

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

Derivative Instruments	September 30, Notional Volumes at June 30, 2011 Derivative Contract Assets	September 30, Derivative Contract Liabilities (in millions)	September 30, Net Derivative Contracts
Commodity Contracts (in equivalent MWh):			
Power(1)	(20)	(35)	(55)
Natural gas	(23)	25	2
Fuel oil	2	(2)	
Coal	7	7	14
Interest Rate Contracts (in dollars)(2)	475		475

Derivative Instruments	September 30, Notional Volumes at December 31, 2010 Derivative Contract Assets	September 30, Derivative Contract Liabilities (in millions)	September 30, Net Derivative Contracts
Commodity Contracts (in equivalent MWh):			
Power(1)	(25)	(26)	(51)

Natural gas	(28)	29	1
Fuel oil	2	(3)	(1)
Coal	10	10	20
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. The interest bearing funds and available-for-sale 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 the interest rate swaps.

Level 3: This category includes the 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, power and natural gas contracts, and options valued using internally developed inputs.

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.

Most 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 that we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes 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 June 30, 2011, we obtained broker quotes for 100% of our delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. Our transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or we are only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, we may apply valuation techniques such as extrapolation and other quantitative methods to determine fair value. Proprietary models may also be used to estimate the fair value of derivative contract assets and liabilities that may be structured or otherwise tailored. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At June 30, 2011, the assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 4% of total derivative contract assets and 10% 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 to us. 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 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.

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,	September 30,	September 30,	September 30,
	June 30, 2011			
	Level 1[(1)]	Level 2[(1)(2)]	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 9	$ 873	$ 11	$ 893
Fuel	2	4	35	41
Total Asset Management	11	877	46	934
Trading Activities	216	253	12	481
Interest Rate Contracts		9		9
Total derivative contract assets	$ 227	$ 1,139	$ 58	$ 1,424
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 11	$ 214	$ 5	$ 230
Fuel	13	4	72	89
Total Asset Management	24	218	77	319
Trading Activities	222	265	8	495
Interest Rate Contracts		1		1
Total derivative contract liabilities	$ 246	$ 484	$ 85	$ 815
Interest-bearing funds[(3)]	$ 1,942	$	$	$ 1,942
Other assets[(4)]	$ 23	$	$	$ 23

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during the six months ended June 30, 2011.

(2) Option contracts comprised approximately 3% of net derivative contract assets.

(3) 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. We had $1.585 billion of interest-bearing funds included in cash and cash equivalents, $156 million included in funds on deposit and $201 million included in other noncurrent assets.

(4) Mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

	September 30,	September 30,	September 30,	September 30,
	December 31, 2010			
	Level 1[1]	Level 2[1][2]	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 1	$ 1,140	$ 6	$ 1,147
Fuel	4	3	37	44
Total Asset Management	5	1,143	43	1,191
Trading Activities	530	385	11	926
Interest Rate Contracts		19		19
Total derivative contract assets	$ 535	$ 1,547	$ 54	$ 2,136
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 12	$ 340	$ 4	$ 356
Fuel	18	2	109	129
Total Asset Management	30	342	113	485
Trading Activities	533	389	9	931
Interest Rate Contracts				
Total derivative contract liabilities	$ 563	$ 731	$ 122	$ 1,416
Interest-bearing funds[3]	$ 2,977	$	$	$ 2,977
Other assets[4]	$ 31	$	$	$ 31

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during 2010.

(2) Option contracts comprised approximately 7% of net derivative contract assets.

(3) 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. We had $2.385 billion of interest-bearing funds included in cash and cash equivalents, $425 million included in funds on deposit and $167 million included in other noncurrent assets.

(4) Includes $13 million in available-for-sale securities (shares in a publicly traded exchange) and $18 million in 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 in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during the six months ended June 30, 2011 and 2010, respectively:

	September 30,	September 30,	September 30,
	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading Activities	Total
		(in millions)	
Balance, January 1, 2011 (net asset (liability))	$ (70)	$ 2	$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	33	4	37
Purchases[(2)]			
Issuances[(2)]			
Settlements[(3)]	6	(2)	4
Transfers into Level 3[(4)]			
Transfers out of Level 3[(4)]			
Balance, June 30, 2011 (net asset (liability))	$ (31)	$ 4	$ (27)
Balance, January 1, 2010 (net asset (liability))	$ 19	$ 13	$ 32
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	(133)	(16)	(149)
Purchases[(2)]			
Issuances[(2)]			
Settlements[(5)]	(16)	22	6
Transfers in and out of Level 3[(4)]	38		38
Balance, June 30, 2010 (net asset (liability))	$ (92)	$ 19	$ (73)

(1) Represents the fair value, as of the end of each quarterly reporting period, of Level 3 contracts entered into during each quarterly reporting period and the gains and losses attributable to Level 3 contracts that existed as of the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period.
(2) Contracts entered into during each quarterly reporting period are reported with other changes in fair value.
(3) Effective January 1, 2011, represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each quarterly reporting period.
(4) Denotes the total contracts that existed at the beginning of each quarterly reporting period and were still held at the end of each quarterly 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 quarterly reporting period. Amounts reflect fair value as of the end of each quarterly reporting period.
(5) Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning of each quarterly reporting period.

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

September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
Three Months Ended June 30,					
	2011			2010	
Operating Revenues	Cost of Fuel, Electricity	Total	Operating Revenues	Cost of Fuel, Electricity	Total

		and Other Products				and Other Products						
				(in millions)								
Gains (losses) included in income	$	2	$	19	$	21	$	(36)	$	(113)	$	(149)
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 June 30	$	3	$	19	$	22	$	(31)	$	(113)	$	(144)

17

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Six Months Ended June 30,					
	2011			2010		
	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	$ 6	$ 35	$ 41	$ 2	$ (107)	$ (105)
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 June 30	$ 7	$ 34	$ 41	$ 7	$ (107)	$ (100)

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 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 do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Our credit valuation adjustment on derivative contract assets was $17 million and $21 million at June 30, 2011 and December 31, 2010, respectively.

At June 30, 2011 and December 31, 2010, $7 million and $3 million, respectively, of cash collateral posted to us by counterparties under master netting agreements were included in accounts payable and accrued liabilities on the consolidated balance sheets.

We also 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,	September 30,	September 30,	September 30,	September 30,
	June 30, 2011				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3)	Exposure Net of Collateral	% of Net Exposure
	(dollars in millions)				
Clearing and Exchange	$ 581	$ 12	$ 12	$	
Investment Grade:					
Financial institutions	723	664		664	68%
Energy companies	398	232	2	230	23%
Non-investment Grade:					
Energy companies	30	24	5	19	2%
No External Ratings:					
Internally-rated investment grade	43	43		43	4%
Internally-rated non-investment grade	27	27		27	3%
Total	$ 1,802	$ 1,002	$ 19	$ 983	100%

Table of Contents

	September 30,	September 30,	September 30, December 31, 2010	September 30,	September 30,
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3)	Exposure Net of Collateral	% of Net Exposure
			(dollars in millions)		
Clearing and Exchange	$ 1,078	$ 74	$ 74	$	
Investment Grade:					
Financial institutions	837	729		729	65%
Energy companies	550	299	2	297	27%
Non-investment Grade:					
Energy companies	31	18		18	2%
No External Ratings:					
Internally-rated investment grade	52	45		45	4%
Internally-rated non-investment grade	34	34	8	26	2%
Total	$ 2,582	$ 1,199	$ 84	$ 1,115	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 the 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 with counterparties and netting of transactions with clearing brokers and exchanges.

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

We had credit exposure to two investment grade counterparties at June 30, 2011 and three investment grade counterparties at December 31, 2010, respectively, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $550 million and $716 million at June 30, 2011 and December 31, 2010, respectively.

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 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 June 30, 2011, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was $62 million for which we had posted collateral of $48 million, including cash and letters of credit.

At June 30, 2011 and December 31, 2010, we had $117 million and $107 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit on 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.

Table of Contents

The carrying amounts and fair values of financial instruments are as follows:

	September 30,	September 30,	September 30,	September 30,
	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Liabilities:				
Long and short-term debt[1]	$ 4,035	$ 4,136	$ 6,081	$ 6,095

(1) The fair value of long- and short-term debt is estimated using reported market prices, when available.

6. Long-Term Debt

Outstanding debt was as follows:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	June 30, 2011			December 31, 2010		
	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 secured notes, due 2014[2]		$	$	6.75%	$	$ 279
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[3]	6.00	688	7	6.00	691	7
Senior unsecured notes, due 2018[4]	9.50	675		9.50	675	
Senior unsecured notes, due 2020[4]	9.875	550		9.875	550	
Unamortized debt discounts		(27)	(2)		(27)	(2)
GenOn Americas Generation:						
Senior unsecured notes, due 2011[5]				8.30%		535
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, net		(2)			(2)	
GenOn North America:						

Senior notes, due 2013[6]				7.375		850
GenOn Marsh Landing:						
Senior secured term loan, due 2017[7]	2.70	3				
Senior secured term loan, due 2023[7]	2.95	6				
Other:						
Capital leases, due 2011 to 2015	7.375-8.19	16	4	7.375-8.19	18	4
PEDFA fixed-rate bonds, due 2036[8]				6.75		371
Adjustment to fair value of debt[9]		(30)	(3)		(32)	14
Total		$ 4,029	$ 6		$ 4,023	$ 2,058

(1) The weighted average stated interest rates are at June 30, 2011 and December 31, 2010.

(2) These notes were discharged at the closing of the Merger on December 3, 2010 and were redeemed on January 3, 2011 at a call price of 102.25% of the principal amount.

(3) 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.

(4) Effective interest rates of 9.75% and 10.25% for senior unsecured notes due 2018 and 2020, respectively.

(5) These notes were repaid on May 2, 2011.

(6) These notes were discharged at the closing of the Merger on December 3, 2010 and were redeemed on January 3, 2011 at a call price of 101.844% of the principal amount.

(7) During the second quarter of 2011, we satisfied the required initial equity contributions of $147 million and GenOn Marsh Landing began borrowing under its credit facility.

(8) These notes were defeased at 103% of principal plus accrued and unpaid interest to the redemption date of June 1, 2011 and were redeemed on that day.

(9) Debt assumed in the Merger was adjusted to fair value on the Merger date. Included in interest expense is amortization of $1 million and $2 million for valuation adjustments related to the assumed debt for the three and six months ended June 30, 2011, respectively.

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At June 30, 2011, outstanding letters of credit were $295 million and availability of borrowings under the revolving credit facility was $493 million.

Senior Unsecured Notes, Due 2018 and 2020

In connection with our obligations under the Registration Rights Agreement with the initial purchasers of these senior secured notes, dated October 4, 2010, we filed a registration statement and completed, in the second quarter of 2011, offerings to exchange the old notes for a like principal amount at maturity of new notes. The new notes have the same terms and conditions as the old notes, including interest rates, maturity dates and covenants.

GenOn Senior Secured Notes Due 2014

The senior secured notes due 2014 (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon the closing of the Merger, the senior secured notes were discharged following the deposit with the trustee of funds sufficient to pay the redemption price thereof, plus accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $285 million at December 31, 2010 and was recorded as restricted cash and included in funds on deposit on the consolidated balance sheet.

On January 3, 2011, the senior secured notes were redeemed at the call price of 102.25% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $285 million and a $1 million loss on early extinguishment of debt was recognized during the three months ended March 31, 2011.

GenOn North America Senior Notes Due 2013

Upon the closing of the Merger, the senior secured notes due 2013 of GenOn North America (issued in 2005) were discharged following the deposit with the trustee of funds sufficient to pay the redemption price thereof, plus accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $866 million at December 31, 2010 and was recorded as restricted cash included in funds on deposit on the consolidated balance sheet.

On January 3, 2011, the senior secured notes were redeemed at the call price of 101.844% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $866 million and a $23 million loss on early extinguishment of debt (in other, net on the consolidated statement of operations) was recognized during the three months ended March 31, 2011, which includes a $16 million premium and $7 million of unamortized debt issuance costs.

GenOn Americas Generation Senior Notes

On May 2, 2011, GenOn Americas Generation repaid the $535 million of senior notes that came due.

PEDFA Fixed-Rate Bonds

The PEDFA bonds (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon the closing of the Merger, the PEDFA bonds were defeased following the deposit with the trustee of funds sufficient to pay the redemption price thereof, plus accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $394 million at December 31, 2010 and was recorded as restricted cash and included in the funds on deposit on the consolidated balance sheet.

On June 1, 2011, the PEDFA bonds were redeemed at the call price of 103% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $394 million and a $1 million gain on extinguishment of debt was recognized during the three and six months ended June 30, 2011.

Table of Contents

7. Guarantees and Letters of Credit

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.

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 (including for 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.

Upon issuance or modification of a guarantee, we determine if the obligation is subject to initial recognition and measurement of a liability and/or disclosure of the nature and terms of the guarantee. Generally, guarantees of the performance of a third party are subject to the recognition and measurement, and the disclosure provisions of the accounting guidance related to guarantees. Such guarantees must initially be recorded at fair value, as determined in accordance with the accounting guidance.

Following is a summary of letters of credit issued and surety bonds provided:

	September 30, June 30, 2011	September 30, December 31, 2010
	(in millions)	
Letters of credit Marsh Landing development project[1]	$ 190	$ 106
Letters of credit rent reserves	142	133
Letters of credit energy trading and marketing activities	70	96
Letters of credit other operating activities	39	38
Surety bonds[2]	47	50
Total	$ 488	$ 423

(1) Includes $146 million and $106 million of cash-collateralized letters of credit at June 30, 2011 and December 31, 2010, respectively.
(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at June 30, 2011 and December 31, 2010.

This note should be read in conjunction with note 10 to our consolidated financial statements in our 2010 Annual Report on Form 10-K.

8. Pension and Other Postretirement Benefit Plans

We have various defined benefit pension plans, other postretirement benefit plans, and defined contribution savings plans. For a further discussion of these plans, see note 8 to our consolidated financial statements in our 2010 Annual Report on Form 10-K.

Table of Contents

Net Periodic Benefit Cost (Credit)

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

	September 30,	September 30,	September 30,	September 30,
	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Service cost	$ 3	$ 2	$	$
Interest cost	6	4	1	1
Expected return on plan assets	(7)	(6)		
Net amortization[1]	1	1	(1)	(2)
Curtailments				(37)
Net periodic benefit cost (credit)	$ 3	$ 1	$	$ (38)

	September 30,	September 30,	September 30,	September 30,
	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Service cost	$ 6	$ 4	$	$
Interest cost	12	8	2	2
Expected return on plan assets	(15)	(11)		
Net amortization[1]	2	1	(2)	(4)
Curtailments				(37)
Net periodic benefit cost (credit)	$ 5	$ 2	$	$ (39)

(1) Net amortization amount includes prior service cost and actuarial gains or losses.

Table of Contents

Immaterial Misstatement of Post-Employment Benefits in Prior Periods

During the second quarter of 2011, we identified an under accrual of post-employment benefits relating to over ten years up to and through 2010. In those years, we did not recognize a liability for future expected costs of benefits for inactive employees who were unable to perform services because of a disability. For 2010, 2009, 2008, 2007 and 2006, our operations and maintenance expense was understated by $0, $1 million, $1 million, $1 million and $2 million, respectively. Our net income/loss for these years was misstated by the same amounts. The misstatements had no effect on cash flows for any of the periods.

To correct the misstatements, we recorded the following immaterial adjustments to the prior period financial statements presented in this Form 10-Q: (a) cumulative increase to accumulated deficit and decrease to stockholders equity of $13 million in the consolidated balance sheet at December 31, 2010 and (b) cumulative increase to other long-term liabilities and total noncurrent liabilities of $13 million in the consolidated balance sheet at December 31, 2010.

9. Stock-Based Compensation

Compensation expense for the stock-based incentive plans was:

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Six Months Ended June 30, 2011	September 30, 2010
		(in millions)		
Stock-based incentive plans compensation expense (pre-tax)[(1)(2)]	$ 5	$ 4	$ 8	$ 8

(1) See note 9 to our consolidated financial statements in our 2010 Annual Report on Form 10-K for information about stock-based incentive plans compensation expense.
(2) No tax benefits related to stock-based compensation were realized during the six months ended June 30, 2011 and 2010 because of our NOL carryforwards.

During February 2011, we granted long-term incentive awards as follows:

Award Vehicle	September 30, Awards Granted	September 30, Vesting Period
Time-based Restricted Stock Units	2,091,599	Vest ratably each year over a three-year period; settled in common stock
Performance-based Restricted Stock Units	1,810,569	Linked to the 2011 short-term incentive plan performance goals, with performance measured at the end of the first year to determine a multiplier between 0% and 200% of the targeted grant; vest ratably each year over three-year period; settled in common stock
Nonqualified Stock Options	4,118,280	Time-based; vest ratably each year over three-year period

10. Earnings Per Share

We calculate basic EPS by dividing income 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, stock options and warrants. Share amounts below reflect Mirant s historical activity for the three and six months ended June 30, 2010 retroactively adjusted to give effect to the Exchange Ratio and include the combined entities for the three and six months ended June 30, 2011.

Table of Contents

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

	September 30, Three Months Ended June 30, 2011	September 30, Three Months Ended June 30, 2010	September 30, Six Months Ended June 30, 2011	September 30, Six Months Ended June 30, 2010
	(in millions, except per share data)			
Net income (loss)	$ (138)	$ (263)	$ (251)	$ 144
Basic and diluted shares:				
Weighted average shares outstanding basic	772	412	771	412
Shares from assumed vesting of restricted stock units	(1)	(1)	(1)	1
Weighted average shares outstanding diluted	772	412	771	413
Basic and Diluted EPS:				
Basic EPS	$ (0.18)	$ (0.64)	$ (0.33)	$ 0.35
Diluted EPS	$ (0.18)	$ (0.64)	$ (0.33)	$ 0.35

(1) Because we incurred a net loss during this period, diluted loss per share is 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:

	September 30, Three Months Ended June 30, 2011	September 30, Three Months Ended June 30, 2010	September 30, Six Months Ended June 30, 2011	September 30, Six Months Ended June 30, 2010
	(in millions)			
Series A Warrants(1)		76		76
Series B Warrants(1)		20		20
Restricted stock units	4	4	4	2
Stock options	19	13	19	13
Total number of antidilutive shares	23	113	23	111

(1) These warrants expired January 3, 2011.

11. Segment Reporting

In conjunction with the Merger, we began reporting in five segments in the fourth quarter of 2010: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. Prior to the Merger, we had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. Amounts for 2010 were reclassified to conform to the current segment presentation. The segments were 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, 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 revenues consist of (a) power generation revenues, (b) contracted and capacity revenues, (c) fuel sales and proprietary trading revenues and (d) power hedging revenues.

The Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia with total net generating capacity of 6,336 MW. The Western PJM/MISO segment (established as a result of the Merger) consists of 23 generating facilities located in Illinois, Ohio and Pennsylvania with total net generating capacity of 7,483 MW. The California segment consists of seven generating facilities located in California, with

Table of Contents

total net generating capacity of 5,363 MW and includes business development and construction activities for GenOn Marsh Landing. The total net generating capacity for California excludes the Potrero generating facility of 362 MW, which was shut down on February 28, 2011. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of nine generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas with total net generating capacity of 5,055 MW. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment. All revenues are generated and long-lived assets are located within the United States.

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

Operating Segments

	September 30, Eastern PJM	September 30, Western PJM/MISO	September 30, California	September 30, Energy Marketing (in millions)	September 30, Other Operations	September 30, Eliminations	September 30, Total
Three Months Ended June 30, 2011:							
Operating revenues[1]	$ 300	$ 293	$ 36	$ 119	$ 64	$	$ 812
Cost of fuel, electricity and other products[2]	116	157	1	88	31		393
Gross margin (excluding depreciation and amortization)	184	136	35	31	33		419
Operating Expenses:							
Operations and maintenance	146	148	39	(2)	40[3]		371
Depreciation and amortization	33	26	14	1	14		88
Gain on sales of assets, net					2		2
Total operating expenses	179	174	53	(1)	56		461
Operating income (loss)	$ 5	$ (38)	$ (18)	$ 32	$ (23)	$	$ (42)

(1) Includes unrealized losses of $27 million, $22 million and $1 million for Eastern PJM, Western PJM/MISO and California, respectively, and unrealized gains of $13 million and $1 million for Energy Marketing and Other Operations, respectively.
(2) Includes unrealized gains of $15 million and $5 million for Eastern PJM and Western PJM/MISO, respectively, and unrealized losses of $2 million for Energy Marketing.
(3) Includes $14 million of merger-related costs.

Table of Contents

	September 30, Eastern PJM	September 30, Western PJM/MISO	September 30, California	September 30, Energy Marketing (in millions)	September 30, Other Operations	September 30, Eliminations	September 30, Total
Six Months Ended June 30, 2011:							
Operating revenues[1]	$ 616	$ 617	$ 72	$ 204	$ 117	$	$ 1,626
Cost of fuel, electricity and other products[2]	254	320	3	157	63		797
Gross margin (excluding depreciation and amortization)	362	297	69	47	54		829
Operating Expenses:							
Operations and maintenance	252	258	78	2	85[3]		675
Depreciation and amortization	64	51	28	1	30		174
Gain on sales of assets, net					1		1
Total operating expenses	316	309	106	3	116		850
Operating income (loss)	$ 46	$ (12)	$ (37)	$ 44	$ (62)	$	$ (21)
Total assets at June 30, 2011	$ 4,643	$ 3,394	$ 724	$ 2,145	$ 3,934[4]	$ (2,478)	$ 12,362

(1) Includes unrealized losses of $78 million, $35 million, $11 million, $10 million and $1 million for Eastern PJM, Western PJM/MISO, Energy Marketing, Other Operations and California, respectively.
(2) Includes unrealized gains of $27 million, $9 million and $2 million for Eastern PJM, Western PJM/MISO and Other Operations, respectively.
(3) Includes $37 million of merger-related costs.
(4) Includes our equity method investment in Sabine Cogen, LP of $23 million.

Operating Segments

	September 30, Eastern PJM	September 30,	September 30, California	September 30,	September 30,	September 30, Eliminations	September 30, Total

		Western PJM/MISO		Energy Marketing (in millions)	Other Operations		
Three Months Ended June 30, 2010:							
Operating revenues[1]	$ 170	$	$ 33	$ 1	$ 40	$	$ 244
Cost of fuel, electricity and other products[2]	250		4		18		272
Gross margin (excluding depreciation and amortization)	(80)		29	1	22		(28)
Operating Expenses:							
Operations and maintenance	117		18	3	(6)		132
Depreciation and amortization	36		7	1	9		53
Gain on sales of assets, net	(1)						(1)
Total operating expenses	152		25	4	3		184
Operating income (loss)	$ (232)	$	$ 4	$ (3)	$ 19	$	$ (212)

(1) Includes unrealized losses of $205 million, $13 million and $13 million for Eastern PJM, Other Operations and Energy Marketing, respectively.

(2) Includes unrealized losses of $112 million for Eastern PJM and unrealized gains of $3 million for Other Operations.

Table of Contents

	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Six Months Ended June 30, 2010:							
Operating revenues[1]	$ 909	$	$ 71	$ 32	$ 112	$	$ 1,124
Cost of fuel, electricity and other products[2]	405		12		62		479
Gross margin (excluding depreciation and amortization)	504		59	32	50		645
Operating Expenses:							
Operations and maintenance	230		38	5	25		298
Depreciation and amortization	69		15	1	19		104
Gain on sales of assets, net	(3)						(3)
Total operating expenses	296		53	6	44		399
Operating income (loss)	$ 208	$	$ 6	$ 26	$ 6	$	$ 246
Total assets at December 31, 2010	$ 4,832	$ 3,846	$ 664	$ 2,771	$ 7,016[3]	$ (3,855)	$ 15,274

(1) Includes unrealized gains of $133 million and $2 million for Eastern PJM and Other Operations, respectively, and unrealized losses of $3 million for Energy Marketing.
(2) Includes unrealized losses of $104 million and $16 million for Eastern PJM and Other Operations, respectively.
(3) Includes our equity method investment in Sabine Cogen, LP of $23 million.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
Operating income (loss) for all segments	$ (42)	$ (212)	$ (21)	$ 246
Interest expense	(96)	(49)	(205)	(99)
Other, net		(1)	(22)	(2)

Income (loss) before income taxes	$	(138)	$	(262)	$	(248)	$	145

12. 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.

Merger-Related Stockholder Litigation

In April 2010, RRI Energy, Mirant and the members of the Mirant board of directors were named as defendants in four purported class action lawsuits filed in the Superior Court of Fulton County, Georgia, brought in connection with the Merger on behalf of proposed classes consisting of holders of Mirant common stock, excluding the defendants and their affiliates: *Rosenbloom v. Cason, et al.*, No. 2010CV184223, filed April 13, 2010; *The Vladmir Gusinsky Living Trust v. Muller, et al.*, No. 2010CV184331, filed April 15, 2010; *Ng v. Muller, et al.*, No. 2010CV184449, filed April 16, 2010; and *Bayne v. Muller, et al.*, No. 2010CV184648, filed April 21, 2010. The complaints alleged, among other things, that the individual defendants breached their fiduciary duties by failing to maximize the value to be received by Mirant s public stockholders and that the other defendants aided and abetted the individual defendants breaches of fiduciary duties. In three of the actions, amended complaints were filed adding allegations that defendants breached their fiduciary duties by failing to disclose certain information in the preliminary joint proxy statement/prospectus related to the Merger. The complaints sought, among other things, rescission of the Merger and/or granting the class members any profits or benefits allegedly improperly received by defendants in connection with the Merger.

28

In August 2010, the court entered an order, consented to by all parties, consolidating the four cases under the caption *In re Mirant Corporation Shareholder Litigation*, No. 2010CV184223, directing that the amended complaint in *Rosenbloom v. Cason, et al*., No. 2010CV1c824223, serve as the operative complaint, and appointing co-lead counsel. In January 2011, the parties entered into a settlement agreement that, upon final approval by the court, would dismiss the actions. The settlement was based on the inclusion of additional disclosures in the Form S-4 filed with the SEC on September 13, 2010. On April 15, 2011, the court gave final approval to the settlement and awarded $555,000 of attorneys fees and expenses to plaintiffs counsel.

Scrubber Contract Litigation

In January 2011, Stone & Webster, the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown facilities, filed three suits against us in the United States District Court for the District of Maryland. Stone & Webster claims that it has not been paid in accordance with the terms of the EPC agreements for the scrubber projects and sought liens against the properties in the amounts of $43.2 million at Chalk Point, $46.8 million at Dickerson and $53.1 million at Morgantown. In March 2011, the court granted liens against the properties. The liens are interlocutory only and will not become final unless and until Stone & Webster is successful in prosecuting its contractual claims. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $143 million of cash (which is included in funds on deposit on the unaudited condensed consolidated balance sheet) in respect of such liens. In June 2011, Stone & Webster filed a motion to amend its lien claims at Chalk Point, Dickerson and Morgantown by an additional $90 million. In the event that such liens are granted, we expect GenOn Mid-Atlantic to reserve an additional $90 million of cash in respect thereof. We dispute 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. Currently, $1.674 billion continues to represent management s best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act. However, if the costs incurred were to equal the amount claimed by Stone &Webster, the total capital expenditures would exceed $1.674 billion by approximately 5%.

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 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. On July 18, 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 the Company in those cases. The fifth case is pending in the State of Nevada Supreme Court on plaintiff s appeal of the dismissal of all its claims by the Eighth Judicial District Court for Clark County, Nevada. We have agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

Environmental Matters

***Conemaugh Actions*.** In April 2007, PennEnvironment and the Sierra Club filed a citizens suit against us in the United States District Court for the Western District of Pennsylvania to enforce provisions of the water discharge permit for the Conemaugh plant, of which we are the operator and have a 16.45% interest. In March 2011, the court granted partial summary judgment on liability against us. In August 2011, the court entered a consent decree settling the enforcement action brought by PennEnvironment and the Sierra Club in exchange for the Conemaugh owners paying an aggregate amount of $5 million in civil penalties, plaintiffs legal fees and funding to support environmental projects that will benefit the Conemaugh River watershed. We are responsible for 16.45% ($822,500) of this amount.

Table of Contents

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 seeks 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. Although we think claims such as this lack legal merit, it is possible that this trend of climate change litigation may continue.

Potomac River NOVs. In 2010, the Virginia DEQ issued several NOVs related to the Potomac River facility. Virginia DEQ asserted that we failed to include required particulate matter data in compliance reports for certain periods in 2009, and that, when the data were later provided, they indicated that particulate matter emissions may have exceeded the permitted limit. We think that the data indicating exceedance of the limit are erroneous. In another NOV, the Virginia DEQ asserted that on one day in each of February 2010 and July 2010 the opacity readings from the facility exceeded the applicable limits in several six-minute intervals. In a third NOV, the Virginia DEQ asserted that we combusted used oils in the facility s boilers without authority under the permit and received one shipment of coal that exceeded the maximum ash content allowed under the permit. In a fourth NOV, issued in February 2011, the Virginia DEQ asserted that in January 2011 we used a sorbent for the removal of SO_2 that was not permitted. We settled these alleged violations for $276,000 with the Virginia DEQ in May 2011.

Montgomery County Carbon Emissions Levy. The Dickerson facility is located in Montgomery County, Maryland, and in May 2010, Montgomery County imposed a levy on major emitters of CO_2 in the county of $5 per ton of CO_2 emitted. We estimated that the CO_2 levy would have imposed $10 million to $15 million per year in levies owed to Montgomery County. In June 2010, we filed an action against Montgomery County in the United States District Court for the District of Maryland seeking a determination that the CO_2 levy was unlawful. In our complaint, we contended that the CO_2 levy violated our equal protection and due process rights, imposed an unconstitutional excessive fine, was an unconstitutional bill of attainder, constituted a prohibited special law under the Maryland Constitution, and was preempted by Maryland law and the RGGI, an interstate compact to which Maryland is a party. In July 2010, the District Court ruled that the CO_2 levy was a tax rather than a fee and granted a motion filed by Montgomery County seeking dismissal of the suit under the federal Tax Injunction Act for lack of jurisdiction. We appealed that ruling to the United States Court of Appeals for the Fourth Circuit. In June 2011, the United States Court of Appeals for the Fourth Circuit overturned the dismissal and remanded the case to the district court. On July 19, 2011, Montgomery County repealed the carbon emissions levy. We have been refunded all amounts previously paid, with interest.

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. In the past decade, 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.

In December 2007, the New Jersey Department of Environmental Protection (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.

Table of Contents

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 April 2011, the EPA addressed one of the two petitions and proposed to find that the SO_2 emissions from the two coal-fired units at the Portland facility significantly contribute to nonattainment and interfere with the maintenance of the one-hour SO_2 NAAQS in New Jersey. The EPA solicited comments on proposals that would require these two units to reduce their SO_2 emission rates in two phases over a period of three years to address these concerns. If the proposed rule is finalized, the two units would need to reduce their SO_2 emission rates, which would require either capital expenditures and higher operating costs or the retirement of these two units, either of which could be material to our results of operations, financial position and cash flows.

Maryland Fly Ash Facilities. We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. Until recently, we disposed of fly ash from our Morgantown station at Faulkner, but it has reached its capacity. We dispose of fly ash from our Morgantown and Chalk Point facilities at Brandywine. We dispose of fly ash from our Dickerson station at Westland. As described below, the MDE has sued us regarding Faulkner and Brandywine and threatened to sue regarding Westland. The MDE also has 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 of the Clean Water Act and Maryland s Water Pollution Control Law at Faulkner. 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 them 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 of the Clean Water Act and Maryland s Water Pollution Control Law at Brandywine. 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 them attorney s 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 intends to sue us for alleged violations of Maryland s water pollution laws at Westland. To date, MDE has not sued us regarding our ash disposal at Westland.

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 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.

Table of Contents

Stay and Settlement Discussions. In June 2011, the MDE agreed to stay the litigation related to Faulkner and Brandywine while we pursue 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 are discussing settlement. As a condition to obtaining the stay, we agreed in principle to pay a civil penalty of $1.9 million to the MDE if we reach a comprehensive settlement regarding all of the allegations related to the three Maryland ash facilities. Accordingly, we accrued $1.9 million at June 30, 2011. We also have developed a technical solution that we think will address the MDE s concerns at the three ash facilities. We have accrued $28 million for the estimated cost of the technical solution. There are no assurances that we will be able to settle the three matters for the amounts that we have accrued and the ultimate resolution of these matters could be material to our results of operations, financial position and cash flows.

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 ($37 million and $36 million at June 30, 2011 and December 31, 2010, respectively) associated with these environmental liabilities as part of the asset retirement obligations.

Remediation Obligations. We are responsible 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 $7 million at June 30, 2011 and December 31, 2010.

Chapter 11 Proceedings

In July 2003, and various dates thereafter, GenOn Energy Holdings and certain of its subsidiaries (collectively, the Mirant Debtors) filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. 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 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 various of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly-owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is governed by managers who are 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 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

Table of Contents

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, The Southern Company (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 (the Southern Company Litigation). Southern Company paid $202 million to MC Asset Recovery in settlement of all claims asserted in the Southern Company 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. We 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.

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. If MC Asset Recovery succeeds in obtaining any recoveries on these avoidance claims, the Commerzbank 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 on December 9, 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.

Complaint Challenging Capacity Rates Under the RPM Provisions of PJM s Tariff

In May 2008, several parties, including the state public utility commissions of Maryland, Pennsylvania, New Jersey and Delaware, ratepayer advocates, certain electric cooperatives, various groups representing industrial electricity users, and federal agencies (the RPM Buyers), filed a complaint with the FERC asserting that capacity auctions held to determine capacity payments under the RPM provisions of PJM s tariff had produced rates that were unjust and unreasonable. The FERC found that no party had violated the RPM provisions of PJM s tariff and that the prices determined during the auctions were in accordance with the tariff s provisions. The RPM Buyers filed a request for rehearing, which the FERC denied in June 2009. On a subsequent appeal, in February 2011, the United States Court of Appeals for the District of Columbia Circuit affirmed the FERC rulings. None of the RPM Buyers asked the D.C. Circuit to reconsider its decision and no party filed for a writ of certiorari. The deadlines for these procedures have passed.

Excess Mitigation Credits

To facilitate the transition to competition in Texas, the Public Utility Commission of Texas (PUCT) imposed excess mitigation credits (EMCs) on CenterPoint that had the effect of lowering monthly charges payable to CenterPoint by retail energy providers. Prior to the sale of our retail business in 2009, we were a retail energy provider. CenterPoint sought recovery of EMCs that it credited to all retail energy providers, including us, and in December 2004 the PUCT ordered that relief. CenterPoint represents that EMCs credited to us totaled $385 million. On appeal, the Texas Third Circuit Court of Appeals ruled that CenterPoint s recovery should exclude EMCs credited to us for our price-to-beat customers, which CenterPoint represents totaled $385 million. Following that ruling, CenterPoint indicated that in the event it was unable to recover the EMC credits applied to us through its rates, it might assert a claim against us for such credits. CenterPoint appealed this ruling to the Texas Supreme Court. On March 18, 2011, the Texas Supreme Court overturned the appeals court and ruled that CenterPoint is entitled to recover from ratepayers as stranded costs EMCs credited to us. In June 2011, the Texas Supreme Court overruled all motions for rehearing filed in the appeal. In light of the Texas Supreme Court s decision, we think CenterPoint will not assert a claim against us for the recovery of EMCs.

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 $69 million (including interest and penalties through June 30, 2011 of $26 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.

13. Subsequent Events

In July 2011, the EPA released its prepublication version of the regulations to replace the CAIR with the CSAPR starting in 2012. CSAPR will be finalized when published in the Federal Register, which we expect to occur in August 2011. The CSAPR will establish limitations on NO_x and/or SO_2 emissions in states included in the program. The NO_x allowances from the CAIR program will not be used in the CSAPR program and accordingly will have no value after 2011. The SO_2 allowances used for compliance in the CAIR program are the Acid Rain Program allowances, which will have negligible value after 2011. The carrying value of NO_x and SO_2 emissions allowances included in property, plant and equipment and intangible assets at June 30, 2011 was $151 million, which we are evaluating for early retirement or impairment as a result of the CSAPR. It is likely that this evaluation will result in a substantial non-cash charge in the third quarter of 2011.

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 2010 Annual Report on Form 10-K.

Overview

With approximately 24,200 MW of net electric generating capacity, we operate across various fuel (natural gas, coal and oil) and technology types, operating characteristics and regional power markets. At June 30, 2011, our generating capacity was 50% in PJM, 22% in CAISO, 11% in NYISO and ISO-NE, 10% in the Southeast and 7% in MISO.

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

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed their merger. See note 2 to our interim financial statements for further discussion of the Merger.

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

Hedging Activities

We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. We hedge economically using products which we expect to be effective to mitigate the price risk of our generation. However, as a result of market liquidity limitations, our hedges often are not an exact match for the generation being hedged, and, we have some risks resulting from price differentials for different delivery points. In addition, we have risks for implied differences in heat rates when we hedge economically power using natural gas. Currently, a significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. At July 12, 2011, our aggregate hedge levels based on expected generation without considering the effects of CSAPR were as follows:

	September 30, 2011(1)	September 30, 2012	September 30, 2013	September 30, 2014	September 30, 2015
Power	85%	47%	18%	17%	10%
Fuel	90%	40%	27%	8%	7%

(1) Percentages represent the period from August through December 2011.

Table of Contents

The Dodd-Frank Act, which was enacted in July 2010 in response to the global financial crisis, increases the regulation of transactions involving OTC derivative financial instruments. The statute provides that standardized swap transactions between dealers and large market participants will have to be cleared and traded on an exchange or electronic platform. Although the provisions and legislative history of the Dodd-Frank Act provide strong evidence that market participants, such as the Company, which utilize OTC derivative financial instruments to hedge commercial risks are not to be subject to these clearing and exchange-trading requirements, it is uncertain what the final implementing regulations will provide. The effect of the Dodd-Frank Act on our business depends in large measure on pending rulemaking proceedings of the CFTC, the SEC and the federal banking regulators. Under the Dodd-Frank Act, entities defined as swap dealers and major swap participants (SD/MSPs) will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. The CFTC and SEC issued a proposed rulemaking to set final definitions for the terms swap dealer and major swap participant among others. Although we do not expect our hedging activity to result in our designation as an SD/MSP, as proposed, the swap dealer definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. In addition, the CFTC and federal banking regulators, who will regulate bank SD/MSPs, separately issued proposed rules to establish capital and margin requirements for SD/MSPs and swap counterparties. While end-user counterparties who are using a swap to hedge or mitigate commercial risk would be generally exempt from mandatory margin requirements under the CFTC s proposal applicable to non-bank SD/MSPs, they would have to post cash margin to bank SD/MSPs if they exceed exposure thresholds under the federal banking regulators proposal. The federal banking regulators rulemaking states that the credit support limit shall be determined by the bank SD/MSPs in accordance with their normal credit processes to set credit limits and to collect initial and variation margin. As proposed, the federal banking regulators rulemaking does not specify a procedure for determining such thresholds and a major question remains of the extent to which end-users and bank SD/MSPs will be free under the proposal to set their own thresholds to avoid the collection of margin from end-users. If applied to our hedging activity, such regulations could materially affect our ability to hedge economically our generation by significantly increasing the collateral costs associated with such activities. Furthermore, the CFTC and prudential regulators proposed capital requirements for SD/MSPs recommend significant and cash-dependent capital requirements for SD/MSPs. The cost of complying with these requirements may be passed through to and imposed on commercial end users indirectly and increase the cost of our hedging activities.

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

Moreover, the CFTC issued a proposal establishing recordkeeping and reporting requirements for swaps entered into before July 21, 2010, whose terms had not expired as of that date, and data relating to swaps entered into on or after July 21, 2010 and prior to the compliance date specified in the CFTC s final swap data reporting rules. Whilst GenOn will have increased reporting and recordkeeping requirements, we do not expect the proposed requirements to have a material effect on our hedging activities.

In terms of the timing for the release and implementation of the rules established by Dodd-Frank, on July 14, 2011, the CFTC issued an Order clarifying the effective date of the provisions in the swap regulatory regime as the CFTC continues to implement rules. The Order provides temporary relief from certain provisions that would otherwise apply to swaps or swap dealers and that would have become effective as of July 16, 2011, until the CFTC completes the rulemakings specified in the Order. This Order is temporary, and it will expire upon the earlier of the effective date of final rules or December 31, 2011.

Capital Expenditures and Capital Resources

During the six months ended June 30, 2011, we invested $178 million for capital expenditures, excluding capitalized interest paid, primarily related to the construction of the Marsh Landing generating facility and maintenance capital expenditures. At June 30, 2011, we have invested $1.521 billion of the $1.674 billion that was budgeted for capital expenditures related to compliance with the Maryland Healthy Air Act. Provisions in the construction contracts for the scrubbers at three of our largest Maryland coal-fired units provide for certain payments to be made after final completion of the projects. The current budget of $1.674 billion continues to represent our best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act. See note 12 to our interim financial statements for further discussion of the scrubber contract litigation.

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 2011 and 2012:

	September 30, July 1, 2011 through December 31, 2011	September 30, 2012
	(in millions)	
Maryland Healthy Air Act	$ 153	$
Other environmental	21	54
Maintenance	55	91
Marsh Landing generating facility	139	301
Other construction	37	7
Other	14	11
Total	$ 419	$ 464

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures. However, we plan to fund a substantial portion of the capital expenditures for the Marsh Landing generating facility with approximately $500 million of project financing debt into which GenOn Marsh Landing entered in October 2010. Other environmental capital expenditures set forth above could significantly increase subject to the content and timing of final rules and future market conditions.

Environmental Matters

We decide to invest capital for environmental controls based on relatively certain regulations and the expected economic returns on the capital. Whether we elect to install additional controls as a result of the CSAPR, pending HAPs regulation or other regulations remains uncertain and depends on, among other things, the content and timing of regulations, the expected effect of regulations on wholesale power prices and allowance prices, as well as the cost of controls, profitability of our generating facilities, market conditions at the time and the likelihood of CO_2 regulation.

The costs associated with more stringent environmental air and water quality requirements, including state-specific or regional regulatory initiatives, may result in coal-fired generating facilities, including some of ours, being retired. Implementation of a program putting a price on emissions of CO_2 in addition to other emissions control requirements could increase the likelihood of retirements of coal-fired generating facilities.

We expect any such industry retirements to contribute to improving supply and demand fundamentals for the remaining generating facilities. Any resulting increased demand for natural gas could increase the spread between natural gas and coal prices, which would also benefit the remaining coal-fired generating facilities. Consequently, we expect industry retirements to result in higher market power prices, which could result in our investing approximately $565 million to $700 million over the next eight years for SCRs and other environmental controls to meet certain air and water quality requirements, which we expect to fund from existing sources of liquidity. Under current and forecasted market conditions, we do not expect installations of scrubbers to be economic at most of our unscrubbed coal-fired facilities. If market prices are even higher than our current expectations, we might invest more for environmental controls.

Given the uncertainty related to these environmental matters, we cannot predict their actual outcome or ultimate effect on our business, and such matters could result in a material adverse effect on our results of operations, financial position and cash flows. See also our discussion under the caption Environmental Matters in note 12 to our interim financial statements, including the discussion of petitions filed by the New Jersey Department of Environmental Protection related to our Portland facility and the discussion regarding our Brandywine, Faulkner and Westland ash facilities.

Cross-State Air Pollution Rule. In 2005, the EPA promulgated the CAIR, which established SO_2 and NO_x cap-and-trade programs applicable directly to states and indirectly to generating facilities in the eastern United States. The NO_x cap-and-trade program has two components, an annual program and an Ozone Season program. The CAIR SO_2 cap-and-trade program builds off the existing acid rain cap-and-trade program but requires generating facilities to surrender twice as many allowances to cover emissions from 2010 through 2014 and approximately three times as many allowances starting in 2015. Florida, Illinois, Maryland, Mississippi, New Jersey, New York, Ohio, Pennsylvania and Virginia are subject to the CAIR s SO_2 trading program and both its NO_x trading programs. Massachusetts is subject only to the CAIR s Ozone Season NO_x trading program. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NO_x and 2010 for SO_2 and more stringent caps going into effect in 2015. On July 11, 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 on December 23, 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. Accordingly, the CAIR will remain effective until it is replaced by a rule consistent with the D.C. Circuit s opinions, which as described below will take place in January 2012.

In July 2011, EPA released its prepublication version of the regulations to replace the CAIR with the CSAPR. CSAPR will be finalized when published in the Federal Register, which we expect to occur in August 2011. The CSAPR addresses interstate transport of emissions of NO_x and SO_2. The CSAPR will establish limitations on NO_x and/or SO_2 emissions from electric generating units that are greater than 25 megawatts and are located in 27 states in the eastern half of the United States whose NO_x and/or SO_2 emissions are determined by the EPA to 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 will create emission budgets for each of the covered states and allocates emissions allowances (denominated in tons of emissions) to each of the 27 states regulated under the CSAPR. Under the EPA federal implementation plan, for each of 2012 and 2013, we will be allocated 31,901, 14,724, and 78,129 allowances under the CSAPR for annual NO_x, ozone-season NO_x, and SO_2, respectively. The CSAPR contemplates that states after 2012 may allocate allowances in a different manner than allocated initially under the CSAPR. The CSAPR will limit each electric generating unit s NO_x and SO_2 emissions to amounts covered by the number of allowances held by that source in allowance accounts under the program (which may be purchased or otherwise acquired from other sources, subject to certain limitations in the rule). The NO_x allowances from the CAIR program will not be used in the CSAPR program and accordingly will have no value after 2011. The SO_2 allowances used for compliance in the CAIR program are the Acid Rain Program allowances, which will have negligible value after 2011. The carrying value of NOx and SO_2 emissions allowances included in property, plant and equipment and intangible assets at June 30, 2011 was $151 million, which we are evaluating for early retirement or impairment as a result of the CSAPR. It is likely that this evaluation will result in a substantial non-cash charge in the third quarter of 2011.

The EPA also has stated that it may issue a subsequent, more stringent rule if it concludes that recent or planned revisions to the particulate matter and ozone NAAQS make necessary more stringent limits on SO_2 and NO_x emissions from electric generating facilities.

HAPs Regulations. In 2005, the EPA issued the CAMR, which would have limited total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. In February 2008, the D.C. Circuit vacated the CAMR and the EPA s decision not to regulate coal- and oil-fired electric utility steam generating units under section 112 of the Clean Air Act, which requires the EPA to develop MACT standards for controlling emissions of all HAPs, including mercury. The EPA and a group representing electricity generators sought review of the D.C. Circuit s decision by the United States Supreme Court. In February 2009, the EPA filed to withdraw its petition for review, stating that it intends to promulgate alternative regulations for electricity generators under section 112 of the Clean Air Act, and the United States Supreme Court subsequently denied the petition for review. As a result of the D.C. Circuit decision, coal-fired and oil-fired generating facilities are now subject to regulation under the section of the Clean Air Act that generally requires the EPA to develop MACT standards to control HAPs, including mercury, from each covered facility. In May 2011, the EPA proposed emission standards for HAPs from coal- and oil-fired units. The EPA proposes to establish limits for mercury, non-mercury metals, certain organics and acid gases. If finalized, these MACT standards will require us to install and operate additional emissions control equipment at some of our facilities, the cost of which may be material and may result in the shutdown or retirement of some of our coal-fired facilities for which operating economics do not justify the required capital expenditures.

RGGI. The RGGI is a multi-state initiative in the Eastern PJM and Northeast outlining a cap-and-trade program to reduce CO_2 emissions from electric generating units with capacity of 25 MW or greater. The RGGI program calls for signatory states, which include Maryland, Massachusetts, New Jersey and New York, to stabilize CO_2 emissions to an established baseline from 2009 through 2014, followed by a 2.5% reduction each year from 2015 through 2018. In June 2011, New Jersey informed RGGI that it is withdrawing from the program effective December 31, 2011. The withdrawal by New Jersey is not expected to have a material effect on our operations.

AB 32. In California, emissions of greenhouse gases are governed by California s Global Warming Solutions Act (AB 32), which requires that statewide greenhouse gas emissions be reduced to 1990 levels by 2020. In December 2008, the CARB approved a Scoping Plan for implementing AB 32. The Scoping Plan requires that the CARB adopt a cap-and-trade regulation by January 2011 and that the cap-and-trade program begin in 2012. The CARB s schedule for developing regulations to implement AB 32 is being coordinated with the schedule of the WCI for development of a regional cap-and-trade program for greenhouse gas emissions. Through the WCI, California is working with other western states and Canadian provinces to coordinate and implement a regional cap-and-trade program. In October 2010, the CARB released its proposed cap-and-trade regulation for public comment, which the CARB approved in December 2010. In March 2011, a California superior court judge enjoined the implementation of the cap-and-trade program and related Scoping Plan measures until the CARB remedies various procedural flaws related to the CARB s environmental review of the Scoping Plan under the California Environmental Quality Act. The CARB appealed the decision. A state appellate court stayed the injunction, allowing the CARB to continue to develop the final cap-and-trade regulation, with adoption targeted for October 2011. However, CARB indicated in June 2011 that while it still intends to initiate the cap-and-trade program in 2012, compliance requirements imposed by the rule will be delayed one year until 2013. Our California generating facilities will be required to comply with the cap-and-trade regulations and related rules when they go into effect. The recently adopted cap-and-trade regulation and any other plans, rules and programs approved to implement AB 32 could adversely affect the costs of operating the facilities.

Water Regulations. In April 2011, the EPA proposed a 316(b) rule that would apply to virtually all existing facilities, including power plants that use cooling water intake structures to withdraw water from waters of the United States. That proposal would impose national standards for reducing mortality for larger, impingeable-sized organisms. It requires permit writers to establish controls for smaller, entrainable-sized organisms on a site-specific basis, taking into account a variety of factors, including costs and benefits. In July 2011, the EPA extended the time in which it will accept public comment until August 18, 2011. The final rule may differ from the proposal as a result of the public comment process. Until the EPA issues the final rule, which it has committed to do by July 2012, there is significant uncertainty regarding what technologies or other measures will be needed to satisfy section 316(b) regulations.

Seward NPDES Permit Appeal. The PADEP issued the Seward generating facility a renewed NPDES permit in July 2010. In September 2010, PennEnvironment, Defenders of Wildlife and the Sierra Club challenged this permit. These environmental groups asserted that there was insufficient public notice of the final permit. In May 2011, the appeal was dismissed because plaintiffs voluntarily dismissed their challenge.

Potrero Shutdown

On February 28, 2011, the Potrero facility was shut down. See note 19 to our consolidated financial statements in our 2010 Annual Report on Form 10-K for further discussion.

Commodity Prices

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

Table of Contents

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 income from operations and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. These are also provided on a pro forma basis for the three and six months ended June 30, 2010. As mentioned above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted income/loss from continuing operations and adjusted EBITDA also exclude, as applicable: (a) merger-related costs, (b) net lower of cost or market adjustments to our commodity inventories, (c) impairment losses, (d) gain/loss on early extinguishment of debt, (e) Western states litigation and similar settlements, (f) large scale remediation and settlement costs, (g) litigation costs for major project disputes, net of recoveries, (h) postretirement benefits curtailment gain, (i) Montgomery County carbon levy assessment prior year reversal and (j) certain other items. We adjust for the subsequent benefit created by commodity inventory utilized in operations that were subject to prior period lower of cost or market adjustments. We exclude or adjust for these items to provide a more meaningful representation of our ongoing results of operations.

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

Table of Contents

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

Consolidated Financial Performance

We reported net losses of $138 million and $263 million during the three months ended June 30, 2011 and 2010, respectively. The change in net loss is detailed as follows:

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 437	$ 312	$ 125
Unrealized gross margin	(18)	(340)	322
Total gross margin (excluding depreciation and amortization)	419	(28)	447
Operating expenses:			
Operations and maintenance	371	132	239
Depreciation and amortization	88	53	35
(Gain) loss on sales of assets, net	2	(1)	3
Total operating expenses	461	184	277
Operating loss	(42)	(212)	170
Other income (expense), net:			
Interest expense, net	(96)	(49)	47
Other, net		(1)	(1)
Total other expense, net	(96)	(50)	46
Loss before income taxes	(138)	(262)	124
Provision for income taxes		1	(1)
Net loss	$ (138)	$ (263)	$ 125

Realized Gross Margin. Our realized gross margin increase of $125 million was principally a result of the following:

an increase of $82 million in contracted and capacity primarily as a result of $115 million from the addition of RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $33 million primarily resulting from lower capacity prices in our Eastern PJM and Other Operations segments and the shutdown of the Potrero generating facility in our California segment;

an increase of $56 million in energy primarily as a result of $72 million from the addition of RRI Energy generating facilities as a result of the Merger and an increase in Energy Marketing as a result of our fuel oil management activities, primarily from the sales of fuel oil. The increase in energy is offset by a decrease in generation volumes in Eastern PJM primarily as a result of outages at certain of our coal-fired baseload units, an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy, and contracting off-peak dark spreads; partially offset by, a decrease of $13 million in realized value of hedges primarily as a result of a decrease in power hedges primarily related to prices offset by an increase in coal hedges primarily related to prices.

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

unrealized losses of $18 million during the three months ended June 30, 2011, which included $58 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $40 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; and

Table of Contents

unrealized losses of $340 million during the three months ended June 30, 2010, which included a $205 million net decrease in the value of hedge and trading contracts for future periods primarily related to increases in forward power prices and the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The $340 million also included $135 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses. Our operating expenses increase of $277 million was principally a result of the following:

- an increase of $239 million in operations and maintenance expense primarily as a result of the addition of RRI Energy generating facilities and corporate costs as a result of the Merger, a $37 million curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees recorded in 2010, a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty), an increase of $11 million in merger-related costs primarily for severance, and an increase in litigation costs for major project disputes, net of recoveries. The increase in operations and maintenance expense was partially offset by a decrease of $12 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to the refund received in the third quarter of 2011 of CO_2 levies paid in 2010; and

- an increase of $35 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger, partially offset by a decrease as a result of a reduction in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses taken in the fourth quarter of 2010, and the shutdown of the Potrero generating facility.

Interest Expense, Net. Our interest expense, net increase of $47 million was principally a result of the following:

- a $69 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger; partially offset by

- a $28 million decrease related to lower interest expense as a result of (a) repayment of the GenOn North America senior secured credit facilities and senior notes in December 2010 and January 2011, respectively, and (b) repayment of the GenOn Americas Generation senior unsecured notes in May 2011.

Adjusted Income/Loss from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income/loss from continuing operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above and note (1) below regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. In order to provide a more meaningful comparison of our results, the following compares actual results for the three months ended June 30, 2011 to pro forma information for the three months ended June 30, 2010 and provides discussion of the changes. The unaudited pro forma information is based on the historical consolidated financial statements of both RRI Energy and Mirant and has been prepared to illustrate the effects of the Merger, assuming the Merger had been consummated on January 1, 2010. The unaudited pro forma information primarily includes the following adjustments, among others:

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

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

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

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

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

The unaudited pro forma results exclude:

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

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

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

	September 30,	September 30,	September 30,
	Three Months Ended June 30,		
	2011	Pro Forma 2010	2010
		(in millions)	
Net Loss	$ (138)	$ (403)	$ (263)
Unrealized losses	18	406	340
Merger-related costs	14		3
Lower of cost or market inventory adjustments, net	(4)	3	3
Gain on early extinguishment of debt	(1)		
Litigation costs for major project disputes, net of recoveries	7		
Montgomery County carbon levy assessment prior year reversal	(8)		
Large scale remediation and settlement costs	30		
Postretirement benefits curtailment gain		(37)	(37)
Other		(5)	
Adjusted income (loss) from continuing operations	(82)	(36)	46
Interest expense, net	96	93	49
Provision for income taxes		1	1
Depreciation and amortization	88	102	53
Adjusted EBITDA	$ 102	$ 160	$ 149

Table of Contents

Adjusted EBITDA was $102 million for the three months ended June 30, 2011 compared to $160 million on a pro forma basis for the same period of 2010. The decline was primarily related to (a) reduction in energy gross margin as a result of reduced generation volumes in Eastern PJM and lower contracted and capacity revenues from Eastern PJM and California and (b) a decrease in realized value of hedges. The decline was partially offset by lower adjusted operating and other expenses, primarily related to merger cost savings.

The adjusted loss from continuing operations was $82 million for the three months ended June 30, 2011 compared to $36 million on a pro forma basis for the same period of 2010. The increase in loss was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in depreciation and amortization expense.

Our net loss was $138 million for the three months ended June 30, 2011 compared to $403 million on a pro forma basis for the same period of 2010. The improvement was primarily a result of higher unrealized gross margin. The improvement was partially offset by an increase in merger-related costs, a postretirement benefits curtailment gain in 2010 that was not repeated in 2011, and the same items that affected adjusted EBITDA.

Segments

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

In the tables below, for 2011, the Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia. The Western PJM/MISO segment consists of 23 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. These seven generating facilities exclude the Potrero generating facility which was shut down on February 28, 2011. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of nine generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Gross Margin Overview

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

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Three Months Ended June 30, 2011						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Energy	$ 50	$ 69	$ 4	$ 20	$ 9	$	$ 152
Contracted and capacity	81	84	31		24		220
Realized value of hedges	65		1		(1)		65
Total realized gross margin	196	153	36	20	32		437
Unrealized gross margin	(12)	(17)	(1)	11	1		(18)

Total gross margin[1]	$	184	$	136	$	35	$	31	$	33	$	$	419

44

Table of Contents

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Three Months Ended June 30, 2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
	(in millions)						
Energy	$ 78	$	$	$ 14	$ 4	$	$ 96
Contracted and capacity	85		29		24		138
Realized value of hedges	74				4		78
Total realized gross margin	237		29	14	32		312
Unrealized gross margin	(317)			(13)	(10)		(340)
Total gross margin[(1)]	$ (80)	$	$ 29	$ 1	$ 22	$	$ (28)

(1) Gross margin excludes depreciation and amortization.

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

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

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

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

Table of Contents

Operating Statistics

Our total margin capture factor was 86% during the three months ended June 30, 2011. The following table summarizes power generation volumes by segment:

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)	September 30, Increase/ (Decrease)
	(in gigawatt hours)			
Eastern PJM:				
Baseload	2,612	3,062	(450)	(15)%
Intermediate	248	277	(29)	(10)%
Peaking	34	64	(30)	(47)%
Total Eastern PJM	2,894	3,403	(509)	(15)%
Western PJM/MISO:				
Baseload	3,804		3,804	N/A
Intermediate	956		956	N/A
Peaking	25		25	N/A
Total Western PJM/MISO	4,785		4,785	N/A
California:				
Intermediate	93	88	5	6%
Peaking	2		2	N/A
Total California	95	88	7	8%
Other Operations:				
Baseload	486	355	131	37%
Intermediate	47	49	(2)	(4)%
Peaking	89	1	88	N/A
Total Other Operations	622	405	217	54%
Total	8,396	3,896	4,500	116%

The total increase in power generation volumes during the three months ended June 30, 2011, as compared to the same period in 2010, was primarily the result of the following:

Eastern PJM. A decrease in our generation volumes primarily as a result of increased outages at certain of our coal-fired baseload units, an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy, and contracting off-peak dark spreads, partially offset by the addition of the RRI Energy generating facilities as a result of the Merger.

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

California. The increase in our generation volumes was primarily related to the addition of RRI Energy generating facilities as a result of the Merger, offset in part by the shutdown of the Potrero generating facility.

Table of Contents

Other Operations. An increase in our Other Operations baseload generation as a result of higher average temperatures in the Northeast and increased peaking generation as a result of the addition of the Southeast assets as a result of the Merger.

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at June 30, 2011 and four generating facilities with total net generating capacity of 5,204 MW at June 30, 2010.

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

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 50	$ 78	$ (28)
Contracted and capacity	81	85	(4)
Realized value of hedges	65	74	(9)
Total realized gross margin	196	237	(41)
Unrealized gross margin	(12)	(317)	305
Total gross margin (excluding depreciation and amortization)	184	(80)	264
Operating Expenses:			
Operations and maintenance	146	117	29
Depreciation and amortization	33	36	(3)
Gain on sales of assets, net		(1)	1
Total operating expenses, net	179	152	27
Operating income (loss)	$ 5	$ (232)	$ 237

Gross Margin

The decrease of $41 million in realized gross margin was principally a result of the following:

a decrease of $28 million in energy, primarily as a result of a decrease in generation volumes as a result of outages at certain of our coal-fired baseload units, an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy, and contracting off-peak dark spreads;

a decrease of $9 million in realized value of hedges, primarily as a result of a $23 million decrease in power hedges resulting from prices, partially offset by a $14 million increase in our coal hedges resulting from prices; and

a decrease of $4 million in contracted and capacity primarily as a result of lower capacity prices offset in part by additional capacity volumes and the addition of the RRI Energy generating facilities as a result of the Merger.

Our unrealized gross margin for both periods reflects the following:

unrealized losses of $12 million during the three months ended June 30, 2011, which included $60 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $48 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; and

unrealized losses of $317 million during the three months ended June 30, 2010, which included a $203 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices and the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The $317 million also includes $114 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Table of Contents

Operating Expenses

The increase of $27 million in operating expenses was principally a result of an increase of $29 million in operations and maintenance expense primarily as a result of a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty), litigation costs for major project disputes, net of recoveries and an increase in outage expenses incurred during the three months ended June 30, 2011 compared to the same period in 2010. The increase in operations and maintenance expense was partially offset by a decrease of $12 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to the refund received in the third quarter of 2011 of CO_2 levies paid in 2010.

Western PJM/MISO

Our Western PJM/MISO segment was established as a result of the Merger and includes 23 generating facilities (all RRI Energy generating facilities) with total net generating capacity of 7,483 MW at June 30, 2011.

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

	September 30, Three Months 2011	September 30, Ended June 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 69	$	$ 69
Contracted and capacity	84		84
Realized value of hedges			
Total realized gross margin	153		153
Unrealized gross margin	(17)		(17)
Total gross margin (excluding depreciation and amortization)	136		136
Operating Expenses:			
Operations and maintenance	148		148
Depreciation and amortization	26		26
Total operating expenses, net	174		174
Operating loss	$ (38)	$	$ (38)

California

Our California segment consists of seven generating facilities with total net generating capacity of 5,363 MW (excluding the Potrero facility of 362 MW, which was shut down on February 28, 2011) at June 30, 2011 and three generating facilities with total net generating capacity of 2,347 MW at June 30, 2010. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

Table of Contents

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

	September 30, Three Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 4	$	$ 4
Contracted and capacity	31	29	2
Realized value of hedges	1		1
Total realized gross margin	36	29	7
Unrealized gross margin	(1)		(1)
Total gross margin (excluding depreciation and amortization)	35	29	6
Operating Expenses:			
Operations and maintenance	39	18	21
Depreciation and amortization	14	7	7
Total operating expenses, net	53	25	28
Operating income (loss)	$ (18)	$ 4	$ (22)

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 28, 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 agreements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

Operating Expenses

The increase of $28 million in operating expenses was principally a result of the following:

- an increase of $21 million in operations and maintenance expense primarily related to the addition of the RRI Energy facilities as a result of the Merger; and

- an increase of $7 million in depreciation and amortization expense related to the addition of the RRI Energy facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility.

Energy Marketing

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

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

	September 30, Three Months Ended June 30, 2011	September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 20	$ 14	$ 6
Total realized gross margin	20	14	6
Unrealized gross margin	11	(13)	24
Total gross margin (excluding depreciation and amortization)	31	1	30
Operating Expenses:			
Operations and maintenance	(2)	3	(5)
Depreciation and amortization	1	1	
Total operating expenses, net	(1)	4	(5)
Operating income (loss)	$ 32	$ (3)	$ 35

Gross Margin

The increase of $6 million in realized gross margin was principally a result of our fuel oil management activities, primarily from the sales of fuel oil.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $11 million during the three months ended June 30, 2011, which included a $7 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; and

- unrealized losses of $13 million during the three months ended June 30, 2010, which included $17 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a $4 million net increase in the value of trading contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at June 30, 2011 and four generating facilities with total net generating capacity of 2,535 MW at June 30, 2010. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Table of Contents

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

	September 30, Three Months 2011	September 30, Ended June 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 9	$ 4	$ 5
Contracted and capacity	24	24	
Realized value of hedges	(1)	4	(5)
Total realized gross margin	32	32	
Unrealized gross margin	1	(10)	11
Total gross margin (excluding depreciation and amortization)	33	22	11
Operating Expenses:			
Operations and maintenance	40	(6)	46
Depreciation and amortization	14	9	5
Gain on sales of assets, net	2		2
Total operating expenses, net	56	3	53
Operating income (loss)	$ (23)	$ 19	$ (42)

Gross Margin

Our unrealized gross margin for both periods reflects the following:

unrealized gains of $1 million during the three months ended June 30, 2011, which primarily represented a net increase in the value of hedge contracts for future periods; and

unrealized losses of $10 million during the three months ended June 30, 2010, which included a $6 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power and fuel prices and $4 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $53 million in operating expenses was principally the result of the following:

an increase of $46 million in operations and maintenance expense primarily related to an increase of $37 million as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees recorded in 2010, an increase of $11 million in merger-related costs and the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease in allocated overhead costs as a result of a change in the allocation methodology as a result of the Merger; and an increase of $5 million in depreciation and amortization expense primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger.

Table of Contents

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Consolidated Financial Performance

We reported a net loss of $251 million and net income of $144 million during the six months ended June 30, 2011 and 2010, respectively. The change in net income/loss is detailed as follows:

	September 30, Six Months Ended June 30, 2011	September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Realized gross margin	$ 926	$ 633	$ 293
Unrealized gross margin	(97)	12	(109)
Total gross margin (excluding depreciation and amortization)	829	645	184
Operating expenses:			
Operations and maintenance	675	298	377
Depreciation and amortization	174	104	70
(Gain) loss on sales of assets, net	1	(3)	4
Total operating expenses	850	399	451
Operating income (loss)	(21)	246	(267)
Other income (expense), net:			
Interest expense, net	(205)	(99)	106
Other, net	(22)	(2)	20
Total other expense, net	(227)	(101)	126
Income (loss) before income taxes	(248)	145	(393)
Provision for income taxes	3	1	2
Net income (loss)	$ (251)	$ 144	$ (395)

Realized Gross Margin. Our realized gross margin increase of $293 million was principally a result of the following:

an increase of $175 million in contracted and capacity primarily as a result of $229 million from the addition of RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $54 million primarily resulting from lower capacity prices in our Eastern PJM and Other Operations segments and the shutdown of the Potrero generating facility in our California segment;

an increase of $120 million in energy primarily as a result of $149 million from the addition of RRI Energy generating facilities as a result of the Merger and an increase in Energy Marketing as a result of our fuel oil management activities, primarily from the sales of fuel oil. The increase in energy was offset in part by a decrease in generation volumes in Eastern PJM primarily as a result of contracting dark spreads and an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy; partially offset by a decrease of $2 million in realized value of hedges primarily as a result of a decrease in power hedges as a result of prices, offset by an increase in coal hedges primarily as a result of prices. The decrease in realized value of hedges was offset in part by a $15 million increase from the addition of RRI Energy generating facilities as a result of the Merger.

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

unrealized losses of $97 million during the six months ended June 30, 2011, which included $127 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $30 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; and

Table of Contents

unrealized gains of $12 million during the six months ended June 30, 2010, which included a $228 million net increase in the value of hedge and trading contracts for future periods primarily related to decreases in forward power and natural gas prices and also included the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was partially offset by $216 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses. Our operating expenses increase of $451 million was principally a result of the following:

- an increase of $377 million in operations and maintenance expense primarily as a result of the addition of RRI Energy generating facilities and corporate costs as a result of the Merger, a $37 million curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM employees recorded in 2010, an increase of $32 million in merger-related costs primarily for severance and a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty). The increase in operations and maintenance expense was partially offset by a decrease of $10 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to refund received in the third quarter of 2011 of CO_2 levies paid in 2010; and

- an increase of $70 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger, partially offset by a decrease as a result of a reduction in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses taken in the fourth quarter of 2010, and the shutdown of the Potrero generating facility.

Interest Expense, Net. Our interest expense, net increase of $106 million was principally a result of the following:

- a $140 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger; partially offset by

- a $48 million decrease related to lower interest expense as a result of (a) repayment of the GenOn North America senior secured credit facilities and senior notes in December 2010 and January 2011, respectively, and (b) repayment of GenOn Americas Generation senior unsecured notes in May 2011.

Other, Net. Our other, net change of $20 million was principally a result of the following:

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

Adjusted Income/Loss from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income/loss from continuing operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. In order to provide a more meaningful comparison of our results, the following compares actual results for the six months ended June 30, 2011 to pro forma information for the six months ended June 30, 2010 and provides discussion of the changes. The unaudited pro forma information is based on the historical consolidated financial statements of both RRI Energy and Mirant and has been prepared to illustrate the effects of the Merger, assuming the Merger had been consummated on January 1, 2010. The unaudited pro forma information primarily includes the following adjustments, among others:

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

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

53

Table of Contents

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

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

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

The unaudited pro forma results exclude:

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

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

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

	September 30,	September 30,	September 30,
	Six Months Ended June 30,		
	2011	Pro Forma 2010	2010
	(in millions)		
Net Income (Loss)	$ (251)	$ (183)	$ 144
Unrealized (gains) losses	97	(73)	(12)
Impairment losses		248[(1)]	
Merger-related costs	37		5
Western states litigation and similar settlements		17[(1)]	
Lower of cost or market inventory adjustments, net	(12)	(11)	6
Loss on early extinguishment of debt	23		
Litigation costs for major project disputes, net of recoveries	7		
Montgomery County carbon levy assessment prior year reversal	(8)		
Large scale remediation and settlement costs	30		
Postretirement benefits curtailment gain		(37)	(37)
Other		(3)	1
Adjusted income (loss) from continuing operations	(77)	(42)	107
Interest expense, net	205	194	99
Provision for income taxes	3	1	1
Depreciation and amortization	174	196	104
Adjusted EBITDA	$ 305	$ 349	$ 311

(1) During the six months ended June 30, 2010, RRI Energy recognized (a) impairment losses of $248 million for its Elrama and Niles generating facilities and (b) $17 million to settle the Western states and other litigation.

Adjusted EBITDA was $305 million for the six months ended June 30, 2011 compared to $349 million on a pro forma basis for the same period of 2010. The decline was primarily related to a reduction in energy gross margin as a result of reduced generation volumes in Eastern PJM and lower contracted and capacity revenues from Eastern PJM and California. The decline was partially offset by lower adjusted operating and other expenses, primarily related to merger cost savings.

The adjusted loss from continuing operations was $77 million for the six months ended June 30, 2011 compared to $42 million on a pro forma basis for the same period of 2010. The increase in loss was primarily related to the same items that affected adjusted EBITDA.

Table of Contents

Our net loss was $251 million for the six months ended June 30, 2011 compared to $183 million on a pro forma basis for the same period of 2010. The increase in loss was primarily a result of lower unrealized gross margin, an increase in merger-related costs and the same items that affected adjusted EBITDA. The increase in loss was partially offset by impairment losses in 2010 related to the Elrama and Niles generating facilities that were not repeated in 2011.

Segments

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

In the tables below, for 2011, the Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia. The Western PJM/MISO segment consists of 23 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. These seven generating facilities exclude the Potrero generating facility which was shut down on February 28, 2011. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of nine generating facilities located in Florida, Massachusetts, Mississippi, New York and Texas. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Gross Margin Overview

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

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Six Months Ended June 30, 2011						
	Eastern PJM	**Western PJM/MISO**	**California**	**Energy Marketing**	**Other Operations**	**Eliminations**	**Total**
	(in millions)						
Energy	$ 111	$ 142	$ 4	$ 58	$ 11	$	$ 326
Contracted and capacity	174	169	64		48		455
Realized value of hedges	128	12	2		3		145
Total realized gross margin	413	323	70	58	62		926
Unrealized gross margin	(51)	(26)	(1)	(11)	(8)		(97)
Total gross margin[(1)]	$ 362	$ 297	$ 69	$ 47	$ 54	$	$ 829

55

Table of Contents

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Six Months Ended June 30, 2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Energy	$ 170	$	$	$ 35	$ 1	$	$ 206
Contracted and capacity	174		59		47		280
Realized value of hedges	131				16		147
Total realized gross margin	475		59	35	64		633
Unrealized gross margin	29			(3)	(14)		12
Total gross margin[(1)]	$ 504	$	$ 59	$ 32	$ 50	$	$ 645

(1) Gross margin excludes depreciation and amortization.

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

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

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

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

56

Table of Contents

Operating Statistics

Our total margin capture factor was 88% during the six months ended June 30, 2011. The following table summarizes power generation volumes by segment:

	September 30,	September 30,	September 30,	September 30,
	Six Months Ended June 30,			
	2011	2010	Increase/ (Decrease)	Increase/ (Decrease)
	(in gigawatt hours)			
Eastern PJM:				
Baseload	6,123	7,034	(911)	(13)%
Intermediate	266	332	(66)	(20)%
Peaking	52	70	(18)	(26)%
Total Eastern PJM	6,441	7,436	(995)	(13)%
Western PJM/MISO:				
Baseload	8,096		8,096	N/A
Intermediate	1,670		1,670	N/A
Peaking	24		24	N/A
Total Western PJM/MISO	9,790		9,790	N/A
California:				
Intermediate	126	211	(85)	(40)%
Peaking	2		2	N/A
Total California	128	211	(83)	(39)%
Other Operations:				
Baseload	864	720	144	20%
Intermediate	65	58	7	12%
Peaking	100	1	99	N/A
Total Other Operations	1,029	779	250	32%
Total	17,388	8,426	8,962	106%

The total increase in power generation volumes during the six months ended June 30, 2011, as compared to the same period in 2010, was primarily the result of the following:

Eastern PJM. A decrease in our generation volumes primarily as a result of contracting dark spreads and an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy, partially offset by the addition of the RRI Energy generating facilities as a result of the Merger.

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

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

Other Operations. An increase in our Other Operations baseload and intermediate generation as a result of higher average temperatures in the Northeast and increased peaking generation as a result of the addition of the Southeast assets as a result of the Merger.

Table of Contents

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at June 30, 2011 and four generating facilities with total net generating capacity of 5,204 MW at June 30, 2010.

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

	September 30, Six Months Ended June 30, 2011	September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 111	$ 170	$ (59)
Contracted and capacity	174	174	
Realized value of hedges	128	131	(3)
Total realized gross margin	413	475	(62)
Unrealized gross margin	(51)	29	(80)
Total gross margin (excluding depreciation and amortization)	362	504	(142)
Operating Expenses:			
Operations and maintenance	252	230	22
Depreciation and amortization	64	69	(5)
Gain on sales of assets, net		(3)	3
Total operating expenses, net	316	296	20
Operating income	$ 46	$ 208	$ (162)

Gross Margin

The decrease of $62 million in realized gross margin was principally a result of the following:

- a decrease of $59 million in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads and an increase in production costs at our Dickerson generating facility as a result of the CO_2 levy;
- a decrease of $3 million in realized value of hedges, primarily as a result of a $35 million decrease in power hedges resulting from prices, offset in part by a $32 million increase in our coal hedges resulting from prices; and
- net change of $0 in contracted and capacity primarily as a result of a $31 million decrease primarily resulting from lower capacity prices, offset by additional capacity volumes and $31 million from the addition of RRI Energy generating facilities as a result of the Merger.

Our unrealized gross margin for both periods reflects the following:

unrealized losses of $51 million during the six months ended June 30, 2011, which included $114 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $63 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; and

unrealized gains of $29 million during the six months ended June 30, 2010, which included a $193 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and also included the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was partially offset by $164 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Table of Contents

Operating Expenses

The increase of $20 million in operating expenses was principally a result of an increase of $22 million in operations and maintenance expense primarily as a result of a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty) and litigation costs for major project disputes, net of recoveries. The increase in operations and maintenance expense was partially offset by a decrease of $10 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to refund received in the third quarter of 2011 of CO_2 levies paid in 2010.

Western PJM/MISO

Our Western PJM/MISO segment was established as a result of the Merger and includes 23 generating facilities (all RRI Energy generating facilities) with total net generating capacity of 7,483 MW at June 30, 2011.

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

	September 30, Six Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 142	$	$ 142
Contracted and capacity	169		169
Realized value of hedges	12		12
Total realized gross margin	323		323
Unrealized gross margin	(26)		(26)
Total gross margin (excluding depreciation and amortization)	297		297
Operating Expenses:			
Operations and maintenance	258		258
Depreciation and amortization	51		51
Total operating expenses, net	309		309
Operating loss	$ (12)	$	$ (12)

California

Our California segment consists of seven generating facilities with total net generating capacity of 5,363 MW (excluding the Potrero facility of 362 MW, which was shut down on February 28, 2011) at June 30, 2011 and three generating facilities with total net generating capacity of 2,347 MW at June 30, 2010. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

Table of Contents

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

	September 30, Six Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
	(in millions)		
Gross Margin:			
Energy	$ 4	$	$ 4
Contracted and capacity	64	59	5
Realized value of hedges	2		2
Total realized gross margin	70	59	11
Unrealized gross margin	(1)		(1)
Total gross margin (excluding depreciation and amortization)	69	59	10
Operating Expenses:			
Operations and maintenance	78	38	40
Depreciation and amortization	28	15	13
Total operating expenses, net	106	53	53
Operating income (loss)	$ (37)	$ 6	$ (43)

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 28, 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 agreements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

The increase of $11 million in realized gross margin was primarily a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility.

Operating Expenses

The increase of $53 million in operating expenses was principally a result of the following:

- an increase of $40 million in operations and maintenance expense related to the addition of the RRI Energy facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility and a reduction in outage costs; and

- an increase of $13 million in depreciation and amortization expense related to the addition of the RRI Energy facilities as a result of the Merger, partially offset by a decrease as a result of the shutdown of the Potrero generating facility.

Table of Contents

Energy Marketing

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

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

	September 30, Six Months Ended June 30, 2011	September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 58	$ 35	$ 23
Total realized gross margin	58	35	23
Unrealized gross margin	(11)	(3)	(8)
Total gross margin (excluding depreciation and amortization)	47	32	15
Operating Expenses:			
Operations and maintenance	2	5	(3)
Depreciation and amortization	1	1	
Total operating expenses, net	3	6	(3)
Operating income	$ 44	$ 26	$ 18

Gross Margin

The increase of $23 million in realized gross margin was principally a result of our fuel oil management activities, primarily from the sales of fuel oil.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $11 million during the six months ended June 30, 2011, which included a $9 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 losses of $3 million during the six months ended June 30, 2010, which included $38 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a $35 million net increase in the value of trading contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at June 30, 2011 and four generating facilities with total net generating capacity of 2,535 MW at June 30, 2010. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Table of Contents

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

	September 30, Six Months Ended June 30, 2011	September 30, 2010	September 30, Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 11	$ 1	$ 10
Contracted and capacity	48	47	1
Realized value of hedges	3	16	(13)
Total realized gross margin	62	64	(2)
Unrealized gross margin	(8)	(14)	6
Total gross margin (excluding depreciation and amortization)	54	50	4
Operating Expenses:			
Operations and maintenance	85	25	60
Depreciation and amortization	30	19	11
Gain on sales of assets, net	1		1
Total operating expenses, net	116	44	72
Operating income (loss)	$ (62)	$ 6	$ (68)

Gross Margin

The decrease of $2 million in realized gross margin was principally a result of the following:

- a decrease of $13 million in realized value of hedges primarily as a result of a decline in the value realized from our power, oil and gas hedges, partially offset by

- an increase of $10 million in energy primarily as a result of increases in prices and generation volumes.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $8 million during the six months ended June 30, 2011, which included $6 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $2 million net decrease in the value of hedge contracts for future periods; and

- unrealized losses of $14 million during the six months ended June 30, 2010, which included $14 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $72 million in operating expenses was principally the result of the following:

an increase of $60 million in operations and maintenance expense primarily related to an increase of $37 million as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees recorded in 2010, an increase of $32 million in merger-related costs and the addition of the RRI Energy generating facilities as result of the Merger, partially offset by a decrease in allocated overhead costs as a result of a change in the allocation methodology as a result of the Merger; and

an increase of $11 million in depreciation and amortization expense primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger.

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 6 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 cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at June 30, 2011 (in millions):

		September 30,
Cash and Cash Equivalents:		
GenOn (excluding GenOn Mid-Atlantic and REMA)	$	1,506
GenOn Mid-Atlantic		53
REMA		43
Total cash and cash equivalents		1,602
Less: cash reserved for other purposes		(12)
Total available cash and cash equivalents		1,590
Availability under GenOn credit facilities[1]		493
Total available cash, cash equivalents and availability under GenOn credit facilities[1]	$	2,083

(1) 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 June 30, 2011, 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.

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

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

(2) At June 30, 2011, $3 million and $6 million were outstanding under the GenOn Marsh Landing senior secured term loan, due 2017 and senior secured term loan, due 2023, respectively.

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

The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At June 30, 2011, GenOn Mid-Atlantic and REMA satisfied the respective restricted payments tests. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $143 million of cash (which is included in funds on deposit on the condensed consolidated balance sheet) in respect of such liens. In June 2011, Stone & Webster filed a motion to amend its lien claims at Chalk Point, Dickerson and Morgantown by an additional $90 million. In the event that such liens are granted, we expect GenOn Mid-Atlantic to reserve an additional $90 million of cash in respect thereof. See note 12.

The ability of GenOn Americas Generation to pay its obligations is dependent on the receipt of dividends from GenOn North America, 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, (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.

Repayment of Debt. On January 3, 2011, we used the proceeds from the Merger-related debt issuances to redeem $285 million (principal and 2.25% premium) of GenOn senior secured notes due 2014 and $866 million (principal and 1.844% premium) of GenOn North America senior unsecured notes due 2013. On May 2, 2011, we repaid GenOn Americas Generation s $535 million of senior notes that came due. On June 1, 2011, we redeemed $382 million (principal plus 3% premium) of PEDFA bonds due 2036. See note 6 to our interim financial statements.

Capital Expenditures. Our capital expenditures, excluding capitalized interest paid, during the six months ended June 30, 2011, were $178 million. We estimate our capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the period July 1, 2011 through December 31, 2012 will be $883 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 cash collateral or letters of credit as credit support for various contractual and other obligations incurred in connection with our commercial and operating activities, including obligations in respect of transmission and interconnection access, participation in power pools, rent reserves, power purchases and sales, fuel and emission purchases and sales, construction and equipment purchases, and other operating activities. Credit support includes cash collateral, letters of credit, surety bonds and financial guarantees. In the event that we default, the counterparty can draw on a letter of credit or apply cash collateral held to satisfy the existing amounts outstanding under an open contract. At June 30, 2011, we had $326 million of posted cash collateral and $295 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 $146 million of cash-collateralized letters of credit in support of the Marsh Landing project. Our liquidity requirements are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility, credit terms with third parties and regulation of energy contracts.

Table of Contents

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

	September 30, June 30, 2011	September 30, December 31, 2010
	(in millions)	
Cash collateral posted energy trading and marketing	$ 286	$ 220
Cash collateral posted other operating activities	40	45
Letters of credit Marsh Landing project[1]	190	106
Letters of credit rent reserves	142	133
Letters of credit energy trading and marketing	70	96
Letters of credit other operating activities	39	38
Surety bonds[2]	47	50
Total	$ 814	$ 688

(1) Includes $146 million and $106 million of cash-collateralized letters of credit at June 30, 2011 and December 31, 2010, respectively.
(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at June 30, 2011 and December 31, 2010.

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 2010 Annual Report on Form 10-K and note 6 to our interim financial statements.

Historical Cash Flows

Continuing Operations

Operating Activities. Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities from continuing operations decreased $135 million for the six months ended June 30, 2011, compared to the same period in 2010, primarily as a result of the following:

Operating expenses. An increase in cash used related to higher operations and maintenance expense of $337 million primarily as a result of the addition of RRI Energy generating facilities as a result of the Merger and an increase in merger-related costs. See Results of Operations in Item 2 for additional discussion of our performance in 2011 compared to the same period in 2010;

Funds on deposit. A decrease in cash provided of $105 million primarily as a result of $99 million of additional collateral posted with our counterparties in 2011 compared to $6 million of additional collateral returned from our counterparties in 2010; and

Interest expense. An increase in cash used of $104 million primarily as a result of debt assumed in the Merger and new debt issued as a result of the Merger. See note 6 to our interim financial statements.

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

Realized gross margin. An increase in cash provided of $259 million in 2011 compared to the same period in 2010 (excluding an out-of-market contract amortization of $15 million in 2011 and lower of cost or market inventory adjustments of $19 million) primarily as a result of the addition of RRI Energy generating facilities as a result of the Merger. See Results of Operations in Item 2 for additional discussion of our performance in 2011 as compared to the same period in 2010;

Table of Contents

Inventory. A decrease in cash used of $119 million primarily related to changes in fuel oil inventory compared to the same period in 2010; and

Other operating assets and liabilities. An increase in cash provided of $33 million related to changes in other operating assets and liabilities.

Investing Activities. Net cash provided by investing activities increased by $1.435 billion for the six months ended June 30, 2011, compared to the same period in 2010. This difference was primarily a result of the following:

Withdrawals from restricted funds on deposit. An increase in cash provided of $1.562 billion primarily related to funds received from the GenOn debt financing on December 3, 2010, which were subsequently placed in restricted deposits at December 31, 2010. The withdrawal of cash was used to repay long-term debt. See note 6 to our interim financial statements;

Other investing. An increase in cash provided of $8 million primarily related to proceeds received from the sale of investments, partially offset by:

Payments into restricted funds on deposit. A decrease in cash provided of $113 million primarily related to funds placed in restricted deposits as a result of our scrubber contract litigation and related liens. See note 12 to our interim financial statements; and

Capital expenditures. An increase in cash used of $23 million primarily related to the construction of our Marsh Landing generating facility, partially offset by a decrease in cash used as a result of payments related to our Maryland scrubber projects in 2010.

Financing Activities. Net cash used in financing activities increased by $1.992 billion for the six months ended June 30, 2011, compared to the same period in 2010. This difference was primarily a result of the repayment of long-term debt. See note 6 to our interim financial statements.

Critical Accounting Estimates

See Management s Discussion and Analysis of Financial Condition and Results of Operations, in Item 7 in our 2010 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.

Table of Contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2010 Annual Report on Form 10-K and notes 1 and 5 to our interim financial statements.

Fair Value Measurements

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

The estimated net fair value of our derivative contract assets and liabilities was a net asset of $609 million and $714 million at June 30, 2011 and 2010, respectively. The following tables provide a summary of the factors affecting the change in fair value of the derivative contract asset and liability accounts for the six months ended June 30, 2011 and 2010:

	September 30,	September 30,	September 30,	September 30,
	Commodity Contracts		Other Contracts	
	Asset Management	Trading	Interest Rate	Total
		(in millions)		
Fair value of portfolio of assets and liabilities at January 1, 2011	$ 706	$ (5)	$ 19	$ 720
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[(1)]	32	(5)	(11)	16
Purchases[(2)]				
Issuances[(2)]				
Settlements[(3)]	(123)	(4)		(127)
Fair value of portfolio of assets and liabilities at June 30, 2011	$ 615	$ (14)	$ 8	$ 609
Fair value of portfolio of assets and liabilities at January 1, 2010	$ 701	$ 1	$	$ 702
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[(1)]	36	44		80
Roll off of previous values[(4)]	(177)	(39)		(216)
Purchases[(2)]				
Issuances[(2)]				
Settlements[(5)]	150	(2)		148
Fair value of portfolio of assets and liabilities at June 30, 2010	$ 710	$ 4	$	$ 714

(1) Represents the fair value, as of the end of each quarterly reporting period, of contracts entered into during each quarterly reporting period and the gains or losses attributable to contracts that existed as of the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period.
(2) Contracts entered into during each quarterly reporting period are reported with other changes in fair value.
(3) Effective January 1, 2011, represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each quarterly reporting period.
(4) Represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each quarterly reporting period.
(5) Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning of each quarterly reporting period.

Table of Contents

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

At June 30, 2011, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	September 30, Remainder of 2011	September 30, 2012	September 30, 2013	September 30, 2014 (in millions)	September 30, 2015	September 30, 2016 and thereafter	September 30, Total fair value
Asset Management:							
Prices actively quoted (Level 1)	$ (10)	$ (10)	$ 3	$ 4	$	$	$ (13)
Prices provided by other external sources (Level 2)	88	174	196	198	3		659
Prices based on models and other valuation methods (Level 3)	(9)	(32)	4		6		(31)
Total asset management	$ 69	$ 132	$ 203	$ 202	$ 9	$	$ 615
Trading Activities:							
Prices actively quoted (Level 1)	$	$ (6)	$	$	$	$	$ (6)
Prices provided by other external sources (Level 2)	(10)	(2)					(12)
Prices based on models and other valuation methods (Level 3)	3	1					4
Total trading activities	$ (7)	$ (7)	$	$	$	$	$ (14)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)		(1)	(4)	(4)	1	16	8
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$	$ (1)	$ (4)	$ (4)	$ 1	$ 16	$ 8

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, forward market implied volatilities and credit risk. For further discussion of how we determine these fair values, see Management s Discussion and Analysis of Financial Condition and Results of Operations Recently Adopted Accounting Guidance and Critical Accounting Estimates Critical Accounting Estimates in Item 7 of our 2010 Annual Report on Form 10-K and note 5 to our interim financial statements.

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a credit valuation adjustment, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $17 million and $21 million at June 30, 2011 and December 31, 2010, respectively.

Table of Contents

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

Our non-collateralized power hedges entered into by GenOn Mid-Atlantic with financial institutions, which represent 40% of our net notional power position at June 30, 2011, are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Our coal contracts included in derivative contract assets and liabilities in the consolidated balance sheets also do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in coal prices. An increase of 10% in the spread of credit default swaps of our trading partners would result in an increase of $2 million in our credit reserve at June 30, 2011.

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

We also monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. See note 5 to our interim financial statements for further discussion of our counterparty credit concentration risk.

Interest Rate Risk

Fair Value Measurement

We are also subject to interest rate risk when discounting to account for time value in determining the fair value of our derivative contract assets and liabilities. The nominal value of our derivative contract assets and liabilities is discounted using a LIBOR forward interest rate curve based on the tenor of our transactions. We estimate that a one percentage point change in market interest rates would result in a change of $17 million to our derivative contract assets and a change of $4 million to our derivative contract liabilities at June 30, 2011.

Debt

Some of our debt is subject to variable interest rates, including our $695 million senior secured term loan and our $788 million senior secured revolving credit facility. Borrowings under these facilities will bear interest at the LIBOR rate plus a margin of 4.25% and 3.50% per annum, respectively. However, for the new term loan facility only, in no event shall the LIBOR rate be less than 1.75% per annum. We do not currently plan to enter into any interest rate swap agreements to mitigate the variable interest rate risk associated with our term loan facility or revolving credit facility. In the future, we may enter into interest rate swaps that involve the exchange of floating for fixed rate interest payments in order to reduce interest rate volatility. However, we may not maintain interest rate swaps with respect to all of our variable rate indebtedness, and any swaps we enter into may not fully mitigate our interest rate risk. With the senior secured term loan fully drawn, it is estimated that a one percentage point change in market interest rates above 1.75% would result in a change in our annual interest expense of approximately $7 million. If the senior secured revolving credit facility was fully drawn, we estimate that a one percentage point change in market interest rates would result in a change in our annual interest expense of approximately $8 million.

The GenOn Marsh Landing credit agreement is also subject to variable interest rates. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s collateral requirements under its PPA with PG&E. Interest on the tranche A term loans is based on a base rate or a LIBOR rate plus an initial applicable margin of 1.5% for base rate loans and 2.5% for LIBOR loans (with such margin increasing 0.25% every three years). Interest on the tranche B term loans is based on a base rate or a LIBOR rate plus an initial applicable margin of 1.75% for base rate loans and 2.75% for LIBOR loans (with such margin increasing 0.25% every three years). GenOn Marsh Landing entered into interest rate swaps to reduce the interest rate risks with respect to the term loan. The effective interest rate that GenOn Marsh Landing will pay for the term loan from the commercial operations date is 5.91% (plus the step-up in margin over time). The interest rate swaps cover 100% of the expected outstanding term loan balances during the operating period and a substantial portion of the expected outstanding term loan balances during the construction period. The remaining borrowings during the construction period are still subject to variability in interest rates. At the projected peak borrowing levels during the construction period, a one percentage point change in market interest rates would result in a change in our annual interest cost of less than $1 million.

Coal Agreement Risk

Our coal supply comes primarily from the Northern Appalachian and Central Appalachian coal regions. We enter into contracts of varying tenors to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2013 and one that extends to 2020. Excluding our Keystone and Conemaugh generating facilities (which are not 100% owned by us) and excluding our Seward generating facility (which burns waste coal supplied by an all-requirements contract), we had exposure to three counterparties at June 30, 2011 and December 31, 2010, respectively, that each represented an exposure of more than 10% of our total coal commitments, by volume, and in aggregate represented approximately 73% and 76% of our total coal commitments at June 30, 2011 and December 31, 2010, respectively.

In addition, we have non-performance risk associated with our coal agreements. There is risk that our coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. If our coal suppliers do not perform in accordance with the agreements, we may have to procure coal in the market to meet our needs, or power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. We seek to mitigate this risk through diversification of coal suppliers, to the extent possible, and through guarantees. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers. Non-performance or default risk by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows. See note 5 to our interim financial statements for our credit concentration tables.

Certain of our coal contracts are not required to be recorded at fair value under the accounting guidance for derivative financial instruments. As such, these contracts are not included in derivative contract assets and liabilities in the consolidated balance sheets. These contracts contain pricing terms that are favorable compared to forward market prices at June 30, 2011, and are projected to provide an $89 million benefit to our realized value of hedges through 2013 as the coal is utilized in the production of electricity.

ITEM 4. CONTROLS AND PROCEDURES

Effectiveness of Disclosure Controls and Procedures

As required by Exchange Act Rule 13a-15(b), our management, including our Chief Executive Officer and our Chief Financial Officer, conducted an assessment of the effectiveness of the design and operation of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of June 30, 2011. Based upon this assessment, our management concluded that, as of June 30, 2011, the design and operation of these disclosure controls and procedures were effective.

Table of Contents

Changes in Internal Control over Financial Reporting

We continue to integrate certain business operations, information systems, processes and related internal control over financial reporting as a result of the Merger. We will continue to assess the effectiveness of our internal control over financial reporting as we execute merger integration activities.

Table of Contents

PART II

ITEM 1. LEGAL PROCEEDINGS

See note 12 to our interim unaudited condensed consolidated financial statements.

Table of Contents

ITEM 6. EXHIBITS

Exhibit No.	Exhibit Name
3.1	Third Restated Certificate of Incorporation of Registrant (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
3.2	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Form S-8 filed December 3, 2010)
3.3	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated May 5, 2011 (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Form 8-K filed May 9, 2011)
3.4	Seventh Amended and Restated Bylaws of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Form S-8 filed with the Securities and Exchange Commission on December 3, 2010)
4.1	Specimen Stock Certificate (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form S-1/A Amendment No. 5, Registration No. 333-48038)
4.2	Rights Agreement between Reliant Resources, Inc. and The Chase Manhattan Bank, as Rights Agent, including a form of Rights Certificate, dated at January 15, 2001 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
4.3	Amendment No. 1 to Rights Agreement, by and between RRI Energy, JPMorgan Chase Bank, N.A., and Computershare Trust Company, N.A., dated at November 23, 2010 (Incorporated herein by reference to the Registrant s Current Report on Form 8-K filed November 23, 2010)
4.5	The Company agrees to furnish to the Securities and Exchange Commission, upon request, a copy of any instrument defining the rights of holders of long-term debt of the Company and all of its consolidated subsidiaries for which financial statements are required to be filed with the Securities and Exchange Commission.
31.1*	Certification of the Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
31.2*	Certification of the Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
32.1*	Certification of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
32.2*	Certification of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
101*	Interactive Data File

* Asterisk indicates exhibits filed herewith.

Table of Contents

SIGNATURES

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

GenOn Energy, Inc.

Date: August 8, 2011

By: /s/ Thomas C. Livengood

Thomas C. Livengood
Senior Vice President and Controller
(Duly Authorized Officer and Principal Accounting Officer)