RRI ENERGY INC
Form 10-K
February 25, 2010

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

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2009**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission file number 1-16455

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

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**76-0655566** *(I.R.S. Employer Identification No.)*
1000 Main Street **Houston, Texas 77002** *(Address and Zip Code of Principal Executive Offices)*	**(832) 357-3000** *(Registrant s Telephone Number, Including Area Code)*

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock Exchange

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

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

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

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. Yes þ No o

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). Yes þ No o

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

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 definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $1,751,959,756 (computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on June 30, 2009, the last business day of the registrant s most recently completed second fiscal quarter).

As of February 11, 2010, the registrant had 353,270,519 shares of common stock outstanding and no shares of common stock were held by the registrant as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement for its 2010 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2009, are incorporated by reference into Part III of this Form 10-K.

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Forward-Looking Statements

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are statements that contain projections, assumptions or estimates about our revenues, income, capital structure and other financial items, our plans and objectives for future operations or about our future economic performance, possible transactions, dispositions, financings or offerings, and our view of economic and market conditions. In many cases, you can identify forward-looking statements by terminology such as anticipate, estimate, believe, continue, could intend, may, plan, potential, predict, should, will, expect, objective, projection, forecast, goal effort, target and other similar words. However, the absence of these words does not mean that the statements are not forward-looking.

Actual results may differ materially from those expressed or implied by the forward-looking statements as a result of many factors or events, including, but not limited to, the following:

Demand and market prices for electricity, capacity, fuel and emission allowances;

The timing and extent of changes in commodity prices;

Limitations on our ability to set rates at market prices;

Legislative, regulatory and/or market developments;

Changes in environmental regulations that constrain our operations or increase our compliance costs;

Competition in the wholesale power markets;

Operating without long-term power sales agreements;

Ineffective hedging activities;

Our ability to obtain adequate fuel supply and/or transmission services;

Interruption or breakdown of our plants;

Failure of third parties to perform contractual obligations;

Failure to meet our debt service obligations or restrictive covenants;

Changes in the wholesale power market or in our evaluation of our plants;

The outcome of pending or threatened lawsuits, regulatory proceedings, tax proceedings and investigations;

Weather-related events or other events beyond our control; and

Financial and economic market conditions and our access to capital.

Other factors that could cause our actual results to differ from our projected results are discussed or referred to in Item 1A of this report. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. Our filings and other important information are also available on our investor page at www.rrienergy.com.

GLOSSARY OF TERMS

ancillary services	Services provided to support transmission grid operations.
BCFe	Billion cubic feet equivalent of natural gas.
Cal ISO	California Independent System Operator.
capacity	Energy that could have been generated at continuous full-power operation during the period.
capacity factor	The ratio of actual net electricity generated to capacity.
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.
Channelview	RRI Energy Channelview LP, RRI Energy Channelview (Texas) LLC, RRI Energy Channelview (Delaware) LLC and RRI Energy Services Channelview LLC.
CO_2	Carbon dioxide.
commercial capacity factor	Generation divided by economic generation.
EBITDA	Earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expense.
economic generation	Estimated generation at 100% plant availability based on an hourly analysis of when it is economical to generate based on the price of power, fuel, emission allowances and variable operating costs.
EITF	Emerging Issues Task Force.
EPA	United States Environmental Protection Agency.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States of America.
GWh	Gigawatt hour.
ISO	Independent system operator.
Kern	Kern River Gas Transmission Company.

LIBOR	London Inter Bank Offered Rate.
MISO	Midwest Independent Transmission System Operator, which is an RTO.
MW	Megawatt.
MWh	Megawatt hour.
net generating capacity	The average of a facility s summer and winter generating capacities, net of auxiliary power.
NO_x	Nitrogen oxides.
NYMEX	New York Mercantile Exchange.

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GLOSSARY OF TERMS
(Continued)

open energy gross margin	Calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs.
open gross margin	Segment profitability measure; consists of open energy gross margin and other margin; excludes the effects of hedges and other items and unrealized gains/losses on energy derivatives.
Orion Power	Orion Power Holdings, Inc. and its subsidiaries.
other margin	Represents power purchase agreements, capacity payments, ancillary services revenues and selective commercial strategies relating to optimizing our assets.
PEDFA	Pennsylvania Economic Development Financing Authority.
PJM	PJM Interconnection, LLC, which is an RTO.
PJM Market	The wholesale and retail electric market operated by PJM primarily in Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia.
REMA	RRI Energy Mid-Atlantic Power Holdings, LLC and its subsidiaries.
RERH Holdings	RERH Holdings, LLC and its subsidiaries.
RPM	Model utilized by PJM to meet load serving entities forecasted capacity obligations via a forward-looking commitment of capacity resources.
RTO	Regional transmission organization.
SEC	United States Securities and Exchange Commission.
SO_2	Sulfur dioxide.

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PART I

Item 1. *Business.*

General

We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through our ownership and operation of and contracting for power generation capacity. Our business consists of four reportable segments: East Coal, East Gas, West and Other. We are a well-capitalized, wholesale generator with more than 14,000 megawatts of power generation plants.

The power generation industry is deeply cyclical and capital intensive. There is the possibility for significant future changes in environmental laws and regulations related to emissions. Competitive power markets are still relatively new and we believe scale and diversity will be important long term.

Over the past 18 months, natural gas and other commodity prices have declined, the spread between gas and coal prices has compressed and the downturn in the economy has reduced demand for electricity. Turmoil in the financial markets has increased the cost of capital and limited its availability. In 2009, we completed the sale of our former retail business, eliminating risk related to collateral posting and contingent capital related to that business. We are focused on managing the risks of operating in the current environment.

While we cannot control commodity prices, cyclicality of the industry or political outcomes, we can position ourselves for the longer term market recovery and industry consolidation that is likely over time. We strive for operating excellence to achieve maximum value from our plants.

For further information about our corporate history, business segments and disposition activities, see notes 1, 20, 21, 22 and 23 to our consolidated financial statements and Selected Financial Data in Item 6 of this Form 10-K.

Operations

We focus on operations excellence and continually improving our efficiency and effectiveness. We are implementing a flexible, plant-specific approach to how we operate and invest to maximize the value of our assets. Our objective is to invest for higher performance levels at higher-margin plants, while maintaining performance at lower-margin plants for the expected longer term market recovery. For further discussion, see Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview Flexible Plant-Specific Operating Model in Item 7 of this Form 10-K.

As of December 31, 2009, we owned, had an interest in, leased or contracted for power from 37 electric power plants with an aggregate net generating capacity of 14,581 MW in five regions of the United States. As of December 31, 2009, the net generating capacity of our plants by reportable segment consisted of approximately 32% East Coal, 28% East Gas, 23% West (gas) and 17% Other. Our coal plants generally dispatch as base-load, and our gas, oil and dual fuel plants primarily dispatch as intermediate and/or peaking capacity. We believe coal-fired plants will play an integral role in meeting the United States energy needs for the foreseeable future. Reduced demand for some coal-fired plants could occur depending on the outcome of various pending environmental laws and regulations. Efficient, well located coal-fired plants with emission controls should have a long-term future in the industry.

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The following table describes our plants as of December 31, 2009:

Segment, Region, Plant[1]	Net Generating Capacity (MW)	Fuel Type
East Coal		
PJM coal		
Cheswick	560	Coal
Conemaugh[2]	281	Coal
Elrama	460	Coal
Keystone[2]	284	Coal
Portland[1]	401	Coal
Seward	525	Coal
Shawville[1][2]	597	Coal
Titus[1]	243	Coal
PJM coal total	3,351	
MISO coal		
Avon Lake	763	Coal
New Castle	333	Coal
Niles	244	Coal
MISO coal total[3]	1,340	
East Coal total	4,691	
East Gas		
PJM gas		
Aurora	878	Gas
Blossburg	19	Gas
Brunot Island	289	Gas
Gilbert	536	Dual
Glen Gardner	160	Dual
Hamilton	20	Dual
Hunterstown	60	Dual
Hunterstown CCGT	810	Gas
Mountain	40	Dual
Orrtanna	20	Oil
Portland[1]	169	Dual
Sayreville	224	Dual
Shawnee	20	Oil
Shawville[1][2]	6	Oil
Titus[1]	31	Dual
Tolna	39	Oil
Warren	68	Dual
Werner	212	Oil

PJM gas total	3,601	
MISO gas		
Shelby	356	Gas
MISO gas total	356	
East Gas total	3,957	

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Segment, Region, Plant[1]	**Net Generating Capacity (MW)**	**Fuel Type**
West		
Coolwater	622	Gas
Ellwood	54	Gas
Etiwanda	640	Gas
Mandalay	560	Gas
Ormond Beach	1,516	Gas
West total	3,392	
Other		
Choctaw	800	Gas
Indian River[4]	587	Dual
Osceola	470	Dual
Sabine[5]	54	Gas
Vandolah[6]	630	Dual
Other total	2,541	
Total	14,581	

(1) We own, have an interest in, lease or contract for power from 37 plants, three of which have units included in both the East Coal and East Gas segments. The financial results are primarily included in the East Coal segment for these three plants.

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

(3) We expect these three plants to move into the PJM region in June 2011.

(4) This plant was mothballed in January 2010.

(5) We own a 50% interest in this facility located in Texas (non-ERCOT) having a net generating capacity of 108 MW. An unaffiliated party owns the other 50%. The table includes our net share of the capacity of this facility.

(6) We are party to a tolling agreement entitling us to 100% of the capacity of this Florida facility having 630 MW of net generating capacity. This tolling agreement expires in 2012 and is treated as an operating lease for accounting purposes.

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The following table reflects operational and financial data for each of our four reportable segments. For further information, see Management s Discussion and Analysis of Financial Condition and Results of Operation Consolidated Results of Operations in Item 7 of this Form 10-K.

	2009		2008		2007	
	GWh	% Economic[(1)]	GWh	% Economic[(1)]	GWh	% Economic[(1)]
Economic Generation[(2)(3)]						
East Coal	24,078.7	61%	27,136.7	67%	31,884.5	79%
East Gas	2,054.7	6%	1,362.5	4%	1,584.2	5%
West	693.4	3%	2,553.9	10%	3,711.8	13%
Other	77.0	1%	74.5	1%	3,802.2	48%
Total	26,903.8	26%	31,127.6	30%	40,982.7	39%
Commercial Capacity Factor[(4)]						
East Coal	82.4%		86.3%		79.0%	
East Gas	95.0%		90.6%		91.2%	
West	88.1%		93.7%		95.5%	
Other	99.1%		82.7%		91.9%	
Total	83.6%		87.1%		82.2%	
Generation[(3)]						
East Coal	19,850.5		23,425.9		25,195.1	
East Gas	1,951.1		1,234.9		1,444.0	
West	611.0		2,393.2		3,543.9	
Other	76.3		61.6		3,493.6	
Total	22,488.9		27,115.6		33,676.6	
Open Energy Unit Margin ($/MWh)[(5)]						
East Coal	$ 12.04		$ 30.69		$ 30.88	
East Gas	10.25		34.01		34.63	
West	22.91		NM(6)		5.64	
Other			16.23		6.87	
Weighted average total	$ 12.14		$ 28.07		$ 25.89	

(1) Generally represents economic generation (hours) divided by maximum generation hours (maximum plant capacity multiplied by 8,760 hours).

(2) Estimated generation at 100% plant availability based on an hourly analysis of when it is economical to generate based on the price of power, fuel, emission allowances and variable operating costs.

(3) Excludes generation related to power purchase agreements, including tolling agreements.

(4) Generation divided by economic generation.

(5) Represents open energy gross margin divided by generation.

(6) NM is not meaningful.

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The following table reflects operational data for each significant plant with impacts on open energy gross margin in our reportable segments. Thus, this table excludes plants that primarily operated under power purchase agreements during the majority of these years as the financial results from those plants are included in other margin. For further information, see Management s Discussion and Analysis of Financial Condition and Results of Operation Consolidated Results of Operations in Item 7 of this Form 10-K.

	Economic Generation (GWh)			Commercial Capacity Factor			Generation (GWh)		
Plant	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Cheswick	3,565.6	2,602.6	3,537.9	77.5%	94.0%	82.2%	2,764.4	2,446.1	2,906.7
Conemaugh	2,144.8	2,311.6	2,397.9	93.2	81.7	88.9	1,998.6	1,888.2	2,130.9
Elrama	410.7	1,400.3	2,882.9	87.3	81.8	68.5	358.6	1,145.2	1,976.0
Keystone	2,353.7	2,408.0	2,386.2	74.7	97.9	85.8	1,757.9	2,357.7	2,046.5
Portland	2,726.6	2,708.6	2,713.7	83.7	79.6	82.8	2,282.0	2,156.1	2,247.8
Seward	4,221.9	4,367.5	4,305.5	80.6	86.4	82.4	3,401.9	3,771.9	3,547.9
Shawville	2,787.9	4,108.1	4,137.1	82.2	84.4	83.5	2,292.7	3,466.5	3,454.2
Titus	1,099.8	1,381.6	1,525.0	86.7	87.3	89.6	953.6	1,206.1	1,367.1
Avon Lake	3,523.5	3,296.2	4,701.0	88.9	86.3	62.1	3,131.6	2,844.3	2,919.3
New Castle	732.1	1,394.3	1,856.4	84.6	90.5	77.4	619.5	1,262.1	1,437.2
Niles	512.1	1,157.9	1,440.9	56.6	76.1	80.6	289.7	881.7	1,161.5
East Coal Total	24,078.7	27,136.7	31,884.5	82.4%	86.3%	79.0%	19,850.5	23,425.9	25,195.1

	Economic Generation (GWh)			Commercial Capacity Factor			Generation (GWh)		
Plant	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Hunterstown CCGT	1,999.3	1,194.1	1,273.4	95.0%	90.6%	93.1%	1,898.6	1,081.6	1,185.4
Other plants	55.4	168.4	310.8	NM(1)	NM(1)	NM(1)	52.5	153.3	258.6
East Gas Total	2,054.7	1,362.5	1,584.2	95.0%	90.6%	91.2%	1,951.1	1,234.9	1,444.0

	Economic Generation (GWh)			Commercial Capacity Factor			Generation (GWh)		
Plant	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Bighorn(2)		582.8	1,437.0	N/A	94.8%	99.9%		552.7	1,435.8
Coolwater	130.6	592.2	698.1	50.5%	92.9	96.5	65.9	550.1	673.7
Mandalay	288.5	581.9	510.2	94.0	97.0	85.6	271.1	564.3	436.7
Ormond Beach	274.3	797.0	1,066.5	99.9	91.1	93.5	274.0	726.1	997.7

West Total	693.4	2,553.9	3,711.8	88.1%	93.7%	95.5%	611.0	2,393.2	3,543.9

	Economic Generation (GWh)			**Commercial Capacity Factor**			**Generation (GWh)**		
Plant	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Channelview(3)			3,520.1	N/A	N/A	93.2%			3,282.3
Choctaw	75.5	71.0	261.1	99.1%	81.8%	72.9	74.8	58.1	190.3
Other plants	1.5	3.5	21.0	NM(1)	NM(1)	NM(1)	1.5	3.5	21.0
Other Total	77.0	74.5	3,802.2	99.1%	82.7%	91.9%	76.3	61.6	3,493.6

(1) NM is not meaningful.

(2) The Bighorn plant was sold in October 2008.

(3) Channelview was deconsolidated in August 2007 and the plant was sold in July 2008.

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The following table reflects revenues by type for each of our reportable segments. For further information, see Management s Discussion and Analysis of Financial Condition and Results of Operation Consolidated Results of Operations in Item 7 of this Form 10-K.

	2009[1]	2008[1]	2007[1]
		(in millions)	
East Coal			
Power generation revenues	$ 756	$ 1,549	$ 1,368
Capacity revenues	171	108	26
Total East Coal	$ 927(2)	$ 1,657(2)	$ 1,394(2)
East Gas			
Power generation revenues	$ 89	$ 176	$ 181
Capacity revenues	178	135	80
Natural gas sales revenues	242	365	267
Total East Gas	$ 509(2)	$ 676(2)	$ 528(2)
West			
Power generation revenues	$ 44	$ 224	$ 227
Capacity revenues	124	152	100
Natural gas sales revenues	139	330	600
Total West	$ 307	$ 706	$ 927
Other			
Power generation revenues	$ 33	$ 107	$ 300
Capacity revenues	63	60	62
Natural gas sales revenues		253(3)	127(3)
Total Other	$ 96	$ 420	$ 489

(1) These amounts exclude $(14) million, $(65) million and $(135) million relating to unrealized gains/losses on energy derivatives, hedges and other items and other revenues not specifically identified to a particular plant or reportable segment for 2009, 2008 and 2007, respectively.

(2) For 2009, 2008 and 2007, we recorded $920 million, $1.6 billion and $1.0 billion, respectively, in revenues from a single counterparty (PJM Interconnection, LLC), which represented 50%, 46% and 31%, respectively, of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(3) We deconsolidated Channelview in August 2007. These amounts represent sales of fuel to Channelview prior to the assets being sold in July 2008.

Markets

In addition to purchasing energy, our customers will, for reliability and to comply with regulations, purchase rights to capacity from our plants. We also provide ancillary services to support transmission grid operations. Our products and services may be provided individually or in combination to investor-owned utilities, municipalities, cooperatives and other companies that serve end users or purchase power at wholesale for resale. We obtain transmission services from various RTOs, ISOs, utilities and municipalities.

We sell energy, ancillary and other energy services in the spot market on an hour-ahead or day-ahead basis, as well as in forward markets for various time periods. We sell our plants capacity in forward markets. A significant portion of our revenues comes from energy sold in the spot market and forward sales of capacity. Most of these energy sales occur in our East Coal segment, primarily in the PJM Market. Our capacity sales primarily occur through the PJM Market s reliability pricing model (RPM) auctions, but also in MISO, Cal ISO and other markets where we enter into agreements with counterparties.

Through the RPM auctions, we have committed approximately 5,500 MW of capacity (3,000 MW for coal plants and 2,500 MW for natural gas plants) through May 2013. We expect that a substantial portion of our PJM capacity will continue to be sold in the PJM Market up to three years in advance. Revenue from these capacity sales is determined by market rules designed to ensure regional reliability, encourage competition and reduce energy price volatility. The California Public Utility Commission and Cal ISO are considering possible enhancements to existing resource adequacy requirements, including alternatives similar to capacity markets designed in New England and PJM.

Most of our plants operate in regions administered by PJM, Cal ISO and MISO and none of our plants is subject to traditional cost-based regulation. We can generally sell at market-determined prices. However, these regional jurisdictions operate under FERC-approved market rules. The market rules include price limits or caps applicable to all electric generators and numerous other FERC-approved requirements relating to the manner in which we must operate our plants, including reliability standards. A number of our subsidiaries are public utilities under the Federal Power Act and are subject to FERC rules and oversight regulations. Each of these subsidiaries has been granted market-based rate authority, although a limited amount of services sold by some of them is sold at cost-based rates.

The following table reflects estimated capacity revenues for 2010 and 2011:

	2010 Estimated	2011 Estimated
	(in millions)	
East Coal(1)(2)	$ 198	$ 164
East Gas(1)(2)	203	164
West	114	95
Other	40	51
Total	$ 555	$ 474

(1) Includes $391 million and $318 million for 2010 and 2011, respectively, related to the PJM Market.

(2) Includes $10 million for 2010 and 2011 related to the MISO Market.

Fuel Supply

To ensure adequate fuel supplies, we contract for natural gas, coal and fuel oil for our plants. For our natural gas-fired plants, we also arrange for, schedule and balance natural gas from our suppliers and through transporting pipelines. To perform these functions, we lease natural gas transportation and storage capacity. Our coal supply strategy has been to contract for our expected delivery needs at least one year in advance with prices generally fixed one year in advance. This has caused volatility in our financial results since our energy sales primarily occur in the spot market. Our modest financial hedging program has mitigated some of our fixed-price coal risk. Going forward, we expect to reduce the levels of our physical coal inventory and will continue to evaluate ways to address volatile coal prices. Under some of our agreements, the counterparties are required to provide fuel supply. We sell excess fuel supplies to third parties. See note 2(c) to our consolidated financial statements and Management s Discussion and Analysis of

Financial Condition and Results of Operations Consolidated Results of Operations in Item 7 of this Form 10-K.

Hedging

We may hedge to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. Our coal procurement strategy is an example of hedging for an operational requirement. We have implemented a modest hedging program for a financial objective. Some of our coal plants 2010 and 2011 generation is hedged so that in the event of a sustained depressed commodity environment, we expect to deliver some minimal level of free cash flow. The rest of our fleet is largely unhedged to benefit from the expected longer term market recovery. For further discussions, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources in Item 7 of this Form 10-K, Quantitative and Qualitative Disclosures about Market Risk in Item 7A of this Form 10-K and notes 2(e) and 6 to our consolidated financial statements.

Other

For further discussion of our business strategy, see Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K. See Risk Factors in Item 1A of this Form 10-K for further discussion on factors that could have an adverse effect on our business.

Competition

The wholesale power generation industry is intensely competitive. Each of our business segments, East Coal, East Gas, West and Other, faces competitors that include other non-utility generators, regulated utilities and other energy service companies, including those owned by investment banking firms, hedge funds and private equity funds. For additional information on the effect of competition, see Risk Factors in Item 1A of this Form 10-K.

Seasonality

A large portion of our margins has historically been realized during our third quarter because most of our plants are located in markets where the greatest demand for power occurs during the summer months. For additional information on the effect of seasonality on our business, see Risk Factors in Item 1A of this Form 10-K and note 19 to our consolidated financial statements.

Environmental Matters

We are subject to numerous federal, state and local requirements relating to the protection of the environment and the safety and health of personnel and the public. These requirements relate to a broad range of our activities, including the discharge of compounds into the air, water and soil; the proper handling of solid, hazardous and toxic materials and waste; noise and safety and health standards applicable to the workplace. Some of these requirements are under revision or in dispute, and some new requirements are pending or under consideration.

We make decisions to invest in environmental capital projects based on relatively certain regulations and the expected economic returns on the capital. Based on existing regulations and our current market outlook and assessment of the costs of labor and materials and the state of evolving technologies, we estimate that we will invest approximately $34 million in 2010, $20 million in 2011 and $34 million in later years primarily on wastewater treatment, coal combustion product management and environmental maintenance capital projects. The 2010 estimate also includes approximately $14 million to complete SO_2 controls at our Cheswick plant. As discussed further below, for years beyond 2011, the amount of environmental investments could significantly increase subject to the form of final regulations and future market conditions, particularly in regard to NO_x, SO_2 and CO_2 emissions. Although we cannot predict the actual outcome or ultimate effect on our business of environmental laws and regulations that are pending, under consideration or revision, or in dispute, we expect them generally to become more stringent in the future. For additional information on how environmental matters may impact our business, see Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K, note 16(b) to our consolidated financial statements and Risk Factors in Item 1A of this Form 10-K.

Air Quality

Under the Clean Air Act, the EPA sets national ambient air quality standards for pollutants considered harmful to public health and the environment, including NO_x, SO_2, ozone and fine particulate matter ($PM_{2.5}$). Emissions of NO_x and SO_2 affect the standards for NO_x and SO_2, are precursors to the formation of ozone and

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$PM_{2.5}$ and contribute to reduced visibility. The EPA and states use local and regional controls to attain and maintain the national ambient air quality standards and to control visibility. The EPA also has authority under the Clean Air Act to control mercury and other hazardous air pollutants from major sources of emissions to the air. In addition, the EPA has been taking steps to regulate greenhouse gas emissions.

National Ambient Air Quality Standards

In April 2009, the New Jersey Department of Environmental Protection finalized a regulation requiring a two-phase reduction in NO_x emissions from combustion turbines in New Jersey. Phase I requires reductions during high electricity demand days and runs from May 2009 through 2014. Under our compliance plan, we operate enhanced NO_x controls at our Shawville, Pennsylvania plant (upwind from New Jersey) on high energy demand days. Phase II requires the installation of emission controls on all of our New Jersey plants (Gilbert, Glen Gardner, Sayreville and Werner) by May 1, 2015. If we elect to install these controls, we could incur capital expenditures of up to approximately $190 million primarily during 2013 to 2015. Our initial Phase II control plan must be filed with the state of New Jersey by May 1, 2010, and our decision on investments should occur by 2012.

In March 2005, the EPA finalized the Clean Air Interstate Rule (CAIR) to reduce emissions of NO_x and SO_2 in the Eastern United States in two phases in order to assist with the attainment of both ozone and $PM_{2.5}$ standards. The first phase, which took effect in 2009 for NO_x and takes effect in 2010 for SO_2, requires overall reductions within the area of approximately 50% in NO_x and SO_2 emissions on an annual basis. The second phase, which takes effect in 2015, requires additional reductions of approximately 10% for a 60% total reduction in NO_x and approximately 15% for a 65% total reduction in SO_2. CAIR is a cap-and-trade program which requires us to provide an emission allowance for each ton of NO_x and SO_2 that we emit. We maintain or have contracts to purchase emission allowances that at a minimum correspond with forward power sales. In general, we do not have emission allowances for all of our generation. We purchase emission allowances, as needed, to correspond with our power generation.

In July 2008, the United States Circuit Court of Appeals for the D.C. Circuit ruled that CAIR was legally flawed, vacated CAIR in its entirety and remanded CAIR to the EPA for revision consistent with the Court s opinion. On rehearing, in December 2008, the Court decided that CAIR will remain in effect until the EPA issues a new rule to replace CAIR in accordance with the July 2008 decision. The EPA has stated that it expects to finalize the new rule in 2011. We may install emission controls at our Conemaugh plant for up to $70 million over several years, expected to begin no sooner than 2012.

Eight of our plants are located in geographic areas that are not in compliance with the existing ozone national ambient air quality standards (nonattainment areas). Following finalization of CAIR, it is possible that additional NO_x emission control measures (in addition to the measures required by CAIR) may be necessary at plants in or near nonattainment areas to meet current or revised ozone standards. These control measures may be part of regional or state implementation plans.

Ten of our eleven coal-fired plants are located in nonattainment areas for $PM_{2.5}$. States must develop emission reduction plans by April 2012 that bring nonattainment areas into compliance by 2014. These plans may be state-specific or regional in scope. The EPA has estimated that the power generation sector SO_2 and NO_x emissions reductions required by CAIR would allow many of the nonattainment areas to achieve compliance with the revised $PM_{2.5}$ standard.

The EPA s primary focus for achieving compliance with visibility standards is on emissions of NO_x and SO_2, particularly from the power sector. The EPA has asserted that the NO_x and SO_2 reductions to be achieved through CAIR should be adequate to provide the improvements in visibility required by 2013.

States are not precluded from developing plans that would require additional reductions in NO_x and SO_2 emissions to meet ozone, $PM_{2.5}$ or visibility improvement goals. In addition, a delay in finalizing the CAIR replacement rule could make additional NO_x and SO_2 reductions necessary.

Hazardous Air Pollutants

In 2000, the EPA found that regulation of hazardous air pollutants, including mercury, from coal and oil-fired power plants was appropriate and necessary, triggering the requirement to regulate such emissions using the Maximum Achievable Control Technology (MACT) standard of the Clean Air Act. In February 2009, the EPA stated its intent to proceed with rulemaking under the MACT standard. This approach considers the most effective control technologies in operation, without regard to cost effectiveness. The EPA has stated it expects to issue rules late in 2011. In the interim, a number of states, including Pennsylvania, pursued mercury regulations. In December 2009, the Pennsylvania Supreme Court upheld a lower court s determination that the proposed Pennsylvania mercury rule was unlawful and unenforceable.

Greenhouse Gas Emissions

There is an increased global focus over the direction of climate change policy. There are currently no federal CO_2 emission regulations with which our plants must comply. However, the United States Congress is considering legislation that would impose mandatory limitation of CO_2 and other greenhouse gas emissions for the domestic power generation sector. In addition, several states in the northeast, midwest and west are increasingly active in developing state-specific or regional regulatory initiatives to stimulate CO_2 emission reductions in the electric power generation industry and other industries.

Ten northeastern states, including New Jersey and Maryland, formed the Regional Greenhouse Gas Initiative, or RGGI, which requires power generators to reduce CO_2 emissions by 10% by 2019, beginning in 2009. California adopted legislation designed to reduce greenhouse gas emissions to 25% below 1990 levels by 2020, beginning in 2012. In July 2008, the Pennsylvania Climate Change Act was adopted. This legislation requires development of reports of the impacts of climate change in Pennsylvania and potential economic opportunities resulting from mitigation strategies. It also requires development of an annual state-level greenhouse gas emissions inventory and establishment of cost-effective state-level strategies for reducing or offsetting greenhouse gases.

In addition, the EPA issued two regulatory findings in December 2009 that are preliminary steps to establishing regulations limiting greenhouse gas emissions. Assuming the EPA finalizes these regulations, New Source Review requirements may apply if a permit is sought for new construction or a major modification to an existing plant, including application to CO_2 emissions of a yet to be defined best available control technology standard. Individual states may also begin to take into account CO_2 emissions when considering permits to construct or modify significant sources of emissions. In 2009, our plants emitted approximately 20.8 million metric tons of CO_2, approximately 90% of which was from our East Coal segment. The amount of CO_2 emissions from our plants will depend on their dispatch time during the period.

In September 2007, we joined the Chicago Climate Exchange, a voluntary greenhouse gas registry, reduction and trading system. By joining the exchange, we have committed to reduce our annual greenhouse gas emissions to six percent below the average of our 1998-2001 levels by 2010 (no more than 28.6 million metric tons in 2010). We continue to satisfy our reduction targets through previously implemented plant retirements and capacity factor reductions, ongoing heat rate improvement efforts and transacting on the exchange.

Water Regulations

In July 2007, the EPA suspended its 2004 regulations relating to cooling water intake structures at large existing power plants pending further rulemaking. This action was in response to the Second Circuit Court of Appeals January 2007 remand of several provisions in the 2004 regulations. In April 2009, the U.S. Supreme Court overturned the Second Circuit on one issue, ruling that the Clean Water Act does not prohibit using cost-benefit analysis in determining appropriate control requirements for cooling water intake structures. The EPA has stated it plans to issue a proposed rule in mid-2010 and has retained interim requirements that plant intakes employ best technology available controls as determined on a plant-by-plant, best professional judgment basis.

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To comply with existing federal rules and subject to market conditions, we may install a cooling tower at one or more of our Shawville, Pennsylvania units for up to $80 million over several years, expected to begin no sooner than 2012.

In September 2009, the EPA announced its intent to revise effluent limitation guidelines for the power generation industry, which are anticipated to result in more stringent regulation. These regulations are applicable to the majority of our plants.

The California State Water Resources Control Board is considering a policy that could result in phasing out the use of coastal water for once-through cooling. If regulations follow this policy, affected plants could be required to install cooling towers or be removed from service. This regulation could impact our Mandalay and Ormond Beach plants.

Coal Combustion Products

Existing state and federal rules require the proper management and disposal of potentially hazardous wastes and other materials. The EPA currently classifies coal combustion products such as fly ash as non-hazardous waste products. Currently, we expect to spend approximately $50 million for ash landfill expansions including approximately $7 million in each of 2010 and 2011 and the remaining amount over several later years. There is increased focus on the regulation of coal combustion products and, if their classifications change, we may be required to change our waste management practices or incur additional costs.

Other

As a result of their age, many of our plants contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. We believe we properly manage and dispose of such materials in compliance with state and federal rules. See note 16(b) to our consolidated financial statements.

We do not believe we have any material liabilities or obligations under the Comprehensive Environmental Response Corporation and Liability Act of 1980 or similar state laws. These laws impose clean up and restoration liability on owners and operators of plants from or at which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances.

Employees

As of December 31, 2009, we had 2,239 full-time and part-time employees. Of these employees, 1,017 are covered by collective bargaining agreements, which expire on various dates from March 31, 2010 through September 30, 2014. The following table sets forth the number of our employees as of December 31, 2009:

Plant operations	1,807
Corporate	432
Total	2,239

Executive Officers

Name	Age(1)	Present Position
Mark M. Jacobs	47	President and Chief Executive Officer
David D. Brast	41	Senior Vice President, Commercial Operations and Origination
Rick J. Dobson	51	Executive Vice President and Chief Financial Officer
David S. Freysinger	50	Senior Vice President, Generation Operations
D. Rogers Herndon	41	Executive Vice President, Strategic Planning and Business Development
Michael L. Jines	51	Executive Vice President, General Counsel and Corporate Secretary and Chief Compliance Officer
Thomas C. Livengood	54	Senior Vice President and Controller
Albert H. Myres	46	Senior Vice President, Government and Public Affairs
Karen D. Taylor	52	Senior Vice President, Human Resources and Chief Diversity Officer

(1) Age is as of February 1, 2010.

Mark M. Jacobs has served as our President and Chief Executive Officer since May 2007. Prior to that, he served as our Executive Vice President and Chief Financial Officer from July 2002 to October 2007.

David D. Brast has served as our Senior Vice President, Commercial Operations and Origination since May 2009. Prior to that, he served as Vice President, Commercial Operations and Origination from June 2003 to May 2009.

Rick J. Dobson has served as our Executive Vice President and Chief Financial Officer since October 2007. Prior to that, he served as Senior Vice President and Chief Financial Officer of Novelis Inc., an international aluminum rolling and recycling company, from July 2006 to August 2007 and Senior Vice President and Chief Financial Officer of Aquila, Inc., an electric and natural gas distribution company that also owns and operates generation assets, from October 2002 to July 2006.

David S. Freysinger has served as our Senior Vice President, Generation Operations since January 2004.

D. Rogers Herndon has served as our Executive Vice President, Strategic Planning and Business Development since June 2009. He served as our Senior Vice President, Strategic Planning and Business Development from November 2007 to June 2009. He was Senior Vice President, Commercial Operations and Origination from May 2006 to November 2007. Prior to that, he was a Managing Director for PSEG Energy Resources and Trade from April 2003 to December 2005.

Michael L. Jines has served as our Executive Vice President, General Counsel and Corporate Secretary and Chief Compliance Officer since June 2009. He served as our Senior Vice President, General Counsel and Corporate Secretary from May 2003 to June 2009.

Thomas C. Livengood has served as our Senior Vice President and Controller since May 2005. Prior to that, he served as our Vice President and Controller from August 2002 to May 2005.

Albert H. Myres has served as our Senior Vice President, Government and Public Affairs since December 2007. He served as Shell Oil Corporation s Chief of Staff and Senior Advisor to the President and Country Chairman from August 2005 to December 2007 and Senior Advisor, Government Affairs from June 2002 to August 2005.

Karen D. Taylor has served as our Senior Vice President, Human Resources since December 2003. In November 2005, she was appointed as our Chief Diversity Officer.

Available Information

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

Our corporate governance guidelines and standing board committee charters

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports

Our business ethics policy

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

Certifications

We will timely provide the annual certification of our Chief Executive Officer to the New York Stock Exchange. We filed last year s certification in July 2009. In addition, our Chief Executive Officer and Chief Financial Officer each have signed and filed the certifications under Section 302 of the Sarbanes-Oxley Act of 2002 with this Form 10-K.

Item 1A. *Risk Factors.*

We are subject to the following factors that could affect our future performance and results of operations. Also, see Forward-Looking Statements on page iii, Business in Item 1 and Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K.

Our financial results are subject to market factors beyond our control. We are exposed to the risk of loss if third parties fail to perform their contractual obligations.

Our results of operations, financial condition and cash flows are significantly impacted by the prevailing demand and market prices for electricity, capacity, fuel and emission allowances over which we have no control. Demand or market prices can fluctuate dramatically in response to many factors, including seasonal and weather conditions; changes in the prices of related commodities; changes in law and regulation; regulatory intervention (including the imposition of price limitations, bidding rules or similar mechanisms); market illiquidity; transmission constraints; environmental limitations; generation unit outages; fuel supply issues; economic conditions; and other events.

Current economic conditions may result in ongoing reduced demand for electricity, commodity price volatility, increased risk of third-party default, changes in law or regulation and other events. We depend on fuel sources and fuel supply facilities owned and operated by third parties to supply our plants. We depend on power transmission facilities owned and operated by third parties to deliver electricity to our customers. We may incur losses if third parties default on their contractual obligations, such as obligations to buy or sell electricity, capacity, fuel or emission allowances; or provide us with fuel and related transportation services or power transmission services. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital

Resources Credit Risk in Item 7 of this Form 10-K and note 2(c) to our consolidated financial statements.

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We operate in relatively immature markets that are characterized by elements of both competitive and regulated markets. Changes in the regulatory environment in which we operate could adversely affect our ability to sell at market rates, or the cost, manner or feasibility of conducting our business.

We operate in a regulatory environment that is undergoing varying restructuring initiatives. In many instances, the regulatory structures governing the electricity markets are still evolving, creating gaps in the regulatory framework and associated uncertainty. In addition, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to our plants or our commercial activities. We cannot predict the future direction of these initiatives or the ultimate effect that this changing regulatory environment will have on our business. However, future regulatory restrictions, regulatory or political intervention or changes in laws and regulations, may constrain our ability to sell at market prices or otherwise have an adverse effect on our business.

The majority of our generation is sold at market prices under market-based rate authority granted by the FERC. Even where market-based rate authority has been granted, the FERC can impose various forms of market mitigation measures, including price caps and operating restrictions. If we lost our market-based rate authority, we may incur additional costs and risks. We also participate in regional power pools, reliability councils, transmission organizations and capacity auctions. Changes in the rules governing such auctions or groups and/or in the composition of such groups may have an adverse effect on our business. Participation in RTOs is voluntary, and transmission owning companies or other RTO members may exit an RTO so long as they do so in compliance with the applicable FERC tariffs and agreements and FERC approval. See Business Markets in Item 1 of this Form 10-K.

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

We are subject to extensive and evolving environmental regulations, particularly in regard to our coal- and oil-fired plants. Failure to comply with environmental requirements could require us to shut down or reduce production at our plants or could create liability exposure. We incur significant costs in complying with these regulations and, if we fail to comply, could incur significant penalties. Our cost estimates for environmental compliance are based on existing regulations or our view of reasonably likely regulations, and our assessment of the costs of labor and materials and the state of evolving technologies. Our decision to make these investments is often subject to future market conditions. Changes to the preceding factors, new or revised environmental regulations, litigation and new legislation and/or regulations, as well as other factors, could cause our actual costs to vary outside the range of our estimates, further constrain our operations, increase our environmental compliance costs and/or make it uneconomical to operate some of our plants. We also may be subject to claims for the environmental liabilities associated with plants even if a prior owner caused the liabilities.

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

Federal, state and regional initiatives to regulate greenhouse gas emissions could have a material impact on our financial performance and condition. The actual impact will depend on a number of factors, including the overall level of greenhouse gas reductions required under any such regulations, the final form of the regulations or legislation, and the price and availability of emission allowances if allowances are a part of the final regulatory framework. See Business Environmental Matters in Item 1, Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K and note 16(b) to our consolidated financial statements.

The operation of plants involves significant risks that could limit, interrupt or shut down operations and increase our costs.

We are exposed to risks relating to the breakdown of our plant equipment or processes; performance below expected levels of output or efficiency; fuel supply or transportation failures or interruptions;

maintenance or construction delays or cost overruns; shortages of or delays in obtaining equipment, material and labor; operational restrictions resulting from environmental limitations and governmental interventions; as well as other risks that could increase our cost of doing business or could cause extended and/or unplanned outages of our plants. If a plant fails or is unavailable, we may have to purchase replacement power from third parties at higher prices and/or we may be subject to contractual or other penalties. In addition, many of our plants are old and require significant maintenance expenditures.

We are party to collective bargaining agreements with labor unions at several of our plants. If our workers were to engage in a strike, work stoppage or other slowdown, other employees were to become unionized or the terms and conditions in future labor agreements were renegotiated, we could experience a significant disruption in our operations and higher ongoing labor costs. Similarly, we have an aging workforce at a number of our plants creating potential knowledge and expertise gaps as those workers retire.

To operate our plants, we must obtain and maintain various permits, licenses, approvals and certificates from governmental agencies. Our failure to obtain or maintain any necessary governmental permits or licenses or to satisfy these legal requirements, including environmental compliance provisions, could limit our ability to operate our plants.

We have insurance, subject to limits and deductibles, covering some types of physical damage and business interruption related to our plants. However, this insurance may not always be available on commercially reasonable terms. In addition, there is no assurance that insurance proceeds will be sufficient to cover all losses, insurance payments will be timely made or the policies themselves will be free of substantial deductibles.

Competition and alternative technologies in wholesale power markets may have a material adverse effect on our financial condition, results of operations and cash flows.

We compete with non-utility generators, regulated utilities, and other energy service companies in the sale of our products and services, as well as in the procurement of fuel and transmission services. We compete primarily on the basis of price and service. Our competitors may have greater access to capital and lower cost structures and/or more efficient power generation facilities. In addition, aggregate demand for power may be met by generation capacity based on competing technologies, as well as power generation facilities fueled by alternative or renewable energy sources. Regulatory initiatives designed to enhance renewable generation could increase competition from these types of facilities.

Our largely unhedged position may cause volatile financial results and any hedging may be ineffective.

We are largely unhedged based on our views of the market. Our uncontracted generation is generally sold on the spot market at current market prices; however, we must maintain coal supply to operate. Therefore, fluctuating commodity prices can affect our financial results and financial position, either favorably or unfavorably. To the extent we hedge, our hedges may not be effective as a result of basis price differences, transmission issues, price correlation, volume variations, margins being compressed as a result of market prices behaving differently than expected or other factors. See note 2(e) to our consolidated financial statements and Quantitative and Qualitative Disclosures About Market Risk in Item 7A of this Form 10-K.

Changes in the wholesale energy market or in our plant operations could result in impairments.

If our outlook for the wholesale energy market changes negatively, or if our ongoing evaluation of our business results in decisions to mothball, retire or dispose of plants, we could have impairment charges related to our fixed assets. These evaluations involve significant judgments about the future. Actual future market prices, project costs and other factors could be materially different from our current estimates. Furthermore, increasing environmental regulatory requirements could result in plants being removed from service or derated. See Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K and note 4 to our consolidated financial statements.

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Significant events beyond our control, such as weather-related problems or acts of terrorism, could have a material adverse effect on our business.

The uncertainty associated with events beyond our control, such as significant weather events, including unseasonable conditions and possible effects from climate change, if any, and the risk of future terrorist activity, may affect our results of operations and financial condition in unpredictable ways. These events could result in a decrease in the demand for power, adverse changes in the insurance markets, disruptions of power and fuel markets or hedging transactions becoming ineffective. In addition, significant weather events or terrorist actions could damage or shut down our plants or the fuel and fuel supply facilities or the power transmission facilities upon which our plants are dependent. These events could also adversely affect the United States economy, create instability in the financial markets and, as a result, have an adverse effect on our ability to access capital on terms and conditions acceptable to us. We are also highly dependent on our specialized computer and communications systems, the operation of which could be interrupted by fire, flood, power loss, computer viruses or similar disruptions. There is no guarantee that our backup systems and disaster recovery plans will be effective. Our business interruption insurance may be limited, as discussed above under The operation of plants involves significant risks that could limit, interrupt or shut down operations and increase our costs.

Our borrowing levels, debt service obligations and restrictive covenants may adversely affect our business. We may be vulnerable to reductions in our cash flow.

As of December 31, 2009, we had total debt of $2.4 billion and off-balance sheet RRI Energy Mid-Atlantic Power Holdings, LLC (REMA) leases of $423 million (collectively referred to below as debt or debt service).

- We must dedicate a portion of our cash flows to debt service, which reduces the amount of cash available for other business purposes;

- The covenants in our debt agreements restrict our ability to, among other things, obtain additional financing, make investments or acquisitions, create additional liens on our assets and take other actions to react to changes or opportunities in our business;

- Our revolving credit facilities require that we maintain a level of net secured debt not to exceed four times our adjusted EBITDA (as defined in the facilities);

- If we do not comply with the payment and other material covenants under our debt agreements, we could be required to repay our debt immediately and, in the case of our revolving credit facilities, the commitment to lend us money could terminate; and

- Our debt levels and credit ratings may affect the evaluation of our creditworthiness by suppliers or customers, which could put us at a competitive disadvantage to competitors with less debt or investment grade credit ratings.

If we were unable to generate sufficient cash flows, access funds from operations or raise cash from other sources, we would not be able to meet our debt service and other obligations. These situations could result from adverse developments in the economy or in the power, fuel or capital markets, a disruption in our operations or those of third parties, or other events adversely affecting our cash flows and financial performance.

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

From time to time, we are named as a party to, or our property is the subject of, lawsuits, regulatory proceedings or tax proceedings. These proceedings involve highly subjective matters with complex factual and legal questions. Their outcome is uncertain. Any claim that is successfully asserted against us could result in significant damage claims and other losses. Even if we prevail, any proceedings could be costly and time-consuming, could divert the attention of our management and key personnel from our business operations and could result in adverse changes in our insurance costs, which could adversely affect our financial condition, results of operations or cash flows. See notes 14, 16 and 17 to our consolidated financial statements.

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

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

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Our principal executive offices are leased through 2018, subject to two five-year renewal options. Our plants are described under Business Operations in Item 1 of this Form 10-K. We believe that our properties are adequate for our present needs. We have satisfactory title, rights and possession to our owned facilities, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3. ***Legal Proceedings.***

For a description of our material pending legal and regulatory proceedings and settlements, see notes 16 and 17 to our consolidated financial statements.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

None.

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PART II

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

Our common stock trades on the New York Stock Exchange under the ticker symbol RRI. On February 11, 2010, we had 33,948 stockholders of record. The closing price of our common stock on December 31, 2009 was $5.72. We have never paid dividends. Some of our debt agreements restrict the payment of dividends. See note 7 to our consolidated financial statements.

	Market Price	
	High	**Low**
2009:		
First Quarter	$ 7.38	$ 2.03
Second Quarter	$ 6.23	$ 3.03
Third Quarter	$ 7.64	$ 4.44
Fourth Quarter	$ 7.21	$ 4.76
2008:		
First Quarter	$ 26.74	$ 18.06
Second Quarter	$ 28.06	$ 20.47
Third Quarter	$ 24.15	$ 4.94
Fourth Quarter	$ 7.60	$ 2.77

The following line graph compares the yearly percentage change in our cumulative total stockholder return on common stock with cumulative total return of a broad equity market index (Standard & Poor s 500 Stock Index), the cumulative total return of a group of our peer companies comprised of Allegheny Energy, Inc., Calpine Corporation, Dynegy Inc., Mirant Corporation, NRG Energy, Inc. and PPL Corporation, and the cumulative total return of a group of peer companies we used for 2008, comprised of Calpine Corporation, Constellation Energy Group, Inc., Dominion Resources, Inc., Dynegy Inc., Exelon Corporation, Mirant Corporation, NRG Energy, Inc., Sempra Energy and TXU Corp. In 2009, we changed our group of peer companies following the sale of our former retail business. This stock price performance graph is furnished in this Form 10-K and is not filed, as permitted by 17 CFR 229.201(e).

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Item 6. ***Selected Financial Data.***

	2009 (1)(2)(3)(4)	2008 (1)(2)(3)(5)(6)	2007 (1)(2)(3)(7)(8)	2006 (1)(2)(3)(9)(10)	2005 (1)(2)(3)(11)
			(in millions)		
Statements of Operations Data:					
Revenues	$ 1,825	$ 3,394	$ 3,203	$ 3,040	$ 3,068
Operating income (loss)	(413)	201	(10)	(207)	(591)
Loss from continuing operations	(479)	(110)	(202)	(374)	(579)
Cumulative effect of accounting changes, net of tax				1	1
Net income (loss)	403	(740)	365	(328)	(331)

	2009 (1)(2)	2008 (1)(2)(3)(5)(6)(7)	2007 (1)(2)(7)(8)	2006 (1)(2)(9)(10)	2005 (1)(2)(11)
Diluted Earnings (Loss) per Share:					
Loss from continuing operations	$ (1.36)	$ (0.32)	$ (0.59)	$ (1.22)	$ (1.91)

	2009 (1)(2)(12)(13)	2008 (1)(2)(5)(6)(12)(13)	2007 (1)(2)(7)(8)(10)(12)(13)	2006 (1)(2)(9)(11)(12)(13)	2005 (1)(2)(12)(13)
			(in millions)		
Statements of Cash Flow Data:					
Cash flows from operating activities	$ 193	$ 183	$ 762	$ 1,276	$ (917)
Cash flows from investing activities	154	216	(179)	1,057	306
Cash flows from financing activities	(509)	(45)	(292)	(1,957)	594

			December 31,		
	2009 (1)(2)(14)	2008 (1)(2)	2007 (1)(2)	2006 (1)(2)	2005 (1)(2)(15)
			(in millions)		
Balance Sheet Data:					
Total assets	$ 7,461	$ 10,722	$ 11,373	$ 11,827	$ 13,569
Current portion of long-term debt and short-term borrowings(16)	405	13	52	355	339
Long-term debt(16)	1,950	2,610	2,642	2,917	4,056
Stockholders equity	4,238	3,778	4,477	3,950	3,864

(1) We sold or transferred the following operations, which have been classified as discontinued operations: Desert Basin, European energy, Orion Power s hydropower plants, Liberty, Ceredo, Orion Power s New York plants and our retail energy business. We sold the following operations, which are included in continuing operations: REMA hydropower plants in April 2005, landfill-gas fueled power plants in July 2005, our El Dorado investment in July 2005 and our Bighorn plant in October 2008.

(2) We deconsolidated Channelview in August 2007 and sold its assets in July 2008. Channelview emerged from bankruptcy in October 2009 and we reconsolidated the entities at that time.

(3) During 2009, 2008, 2007, 2006 and 2005, we had net gains on sales of assets and emission and exchange allowances of $22 million, $93 million, $26 million, $159 million and $168 million, respectively.

(4) During 2009, we recorded non-cash long-lived assets impairments of $211 million related to our New Castle and Indian River plants.

(5) During 2008, we recorded a non-cash goodwill impairment charge of $305 million related to our historical wholesale energy segment.

(6) During 2008, we recorded $37 million in expenses and paid $34 million for Western states litigation and similar settlements relating to natural gas cases.

(7) During 2007, we recorded and paid a $22 million charge related to resolution of a 2004 indictment for alleged violations of the Commodity Exchange Act, wire fraud and conspiracy charges.

(8) During 2007, we recorded $73 million in debt extinguishments expenses and expensed $41 million of deferred financing costs related to accelerated amortization for refinancings and extinguishments.

(9) During 2006, we recorded $37 million in debt conversion expense.

(10) During 2006, we recorded a $35 million charge (paid in 2007) related to a settlement of certain class action natural gas cases relating to the Western states energy crisis.

(11) During 2005, we recorded charges of $359 million relating to various settlements associated with the Western states energy crisis, which were paid during 2006.

(12) During 2009, 2008, 2007, 2006 and 2005, we had net cash proceeds from sales of assets of $36 million, $527 million, $82 million, $1 million and $149 million, respectively.

(13) During 2009, 2008, 2007, 2006 and 2005, we had net proceeds from sales of (purchases of) emission and exchange allowances of $(3) million, $(19) million, $(85) million, $183 million and $89 million, respectively.

(14) See note 15 to our consolidated financial statements for discussion of our contingencies.

(15) The balance sheet data for total assets as of December 31, 2005 has not been reclassified for the adoption of accounting guidance relating to the offsetting of amounts for contracts with a single counterparty as it was impracticable to reasonably retrieve and reconstruct the historical information due to migration of data driven by a system conversion.

(16) Amounts exclude debt related to discontinued operations for December 31, 2008, 2007, 2006 and 2005.

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

Business Overview

Strategy. We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive power generation markets in the United States. Our objective is to be the best performing, best positioned generator in competitive electricity markets.

The power generation industry is deeply cyclical and capital intensive. Given the nature of the industry, we believe scale and diversity are important long term. Given these beliefs, our strategy is to:

- Maintain a capital structure that positions us to manage through the cycles
- Focus on operational excellence

Employ a flexible plant-specific operating model through the cycle

Utilize a disciplined capital investment approach

Create value from industry consolidation

The current market environment is challenging given the uncertainty in the financial markets, possible legislative and regulatory environmental matters and the pace of economic and power demand recovery. Additionally, current commodity prices and spreads are depressed relative to historical levels. While we believe these conditions will improve, the timing is uncertain. Our primary focus is on managing the risks of operating in this current environment.

We have taken a number of actions to navigate the current market challenges, capture the value of our existing assets and position us for the longer term market recovery, while maximizing cash flow and building ample liquidity. Some of these actions include:

Selling the retail business

Focusing on operating efficiency and effectiveness

Implementing flexible plant-specific operating models

Implementing a modest hedging program to achieve a high probability of achieving free cash flow breakeven or better even if market conditions deteriorate further

We are regularly assessing the impact on our business of a wide variety of economic and commodity price scenarios, and believe we have the ability to operate through an extended downturn, if that should occur.

Key Earnings Drivers. Our financial results are significantly impacted by supply and demand fundamentals in the regions in which we operate as well as the spread between gas and coal prices. Plants with lower costs dispatch ahead of higher cost plants to meet demand, with the price of electricity being set by the last plant dispatched.

The specific factors that drive our margins include the prices of power, capacity, natural gas, coal and fuel oil, the cost of emission allowances and transmission, as well as weather and economic factors, many of which are volatile. Our ability to control these factors is limited, and in most instances, the factors are beyond our control. We have the most control over the percentage of time that our plants are available to run when it is economical for them to do so (commercial capacity factor). Our key earnings drivers and various factors that affect these earnings drivers include:

Economic generation (amount of time our plants are economical to operate)

Supply and demand fundamentals

Plant fuel type and efficiency

Absolute and relative cost of fuels used in power generation

Commercial capacity factor (generation as a percentage of economic generation)

Operations excellence effectiveness

- Maintenance practices
- Planned and unplanned outages

Unit margin

- Supply and demand fundamentals
- Commodity prices and spreads
- Plant fuel type and efficiency

Other margin (primarily capacity sales)

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Supply and demand fundamentals

Power purchase agreements sold to others

Ancillary services

Equipment performance

Costs

Operating efficiency

Maintenance practices

Generation asset fuel type

Planned and unplanned outages

Hedges

Hedging strategy

Volumes

Commodity prices

Effectiveness

Flexible Plant-Specific Operating Model. We have different operating approaches for our plants. These operating approaches are determined by each plant s condition, environmental controls, profitability, market rules, upside potential and value drivers. We have separated our plants into four groups for the purpose of developing an operating model.

Long-term value This part of our fleet, representing approximately 2,500 MW, is well positioned to generate revenue for the foreseeable future, and we would expect that little environmental investment will be needed in future years. We plan to invest and manage these plants for current and long-term profitability for both capacity and energy revenues. Our plants in this group are: Cheswick, Conemaugh, Keystone, Seward and Hunterstown and their combined open gross margin was $265 million, $474 million and $381 million during 2009, 2008 and 2007, respectively.

Long-term capacity resource These plants, representing approximately 4,400 MW, are also well positioned to generate revenue for the foreseeable future, and we expect little future environmental investment. We plan to invest in this part of our fleet for long-term profitability from capacity and/or power purchase agreements. Our plants in this group are: Aurora, Blossburg, Brunot Island, Hamilton, Mountain, Orrtanna, Shawnee, Tolna, Warren, Shelby, Coolwater, Ellwood, Etiwanda, Choctaw and Osceola and their combined open gross margin was $158 million, $147 million and $146 million during 2009, 2008 and 2007, respectively.

Near-term profit/controls These plants, representing approximately 5,400 MW, are well positioned to generate revenue in the current environment but may require further investment in environmental controls. We expect to maintain near-term profitability and preserve our options for supply/demand recovery and/or improved gas-coal spreads in this group of plants. We may install environmental controls in the future depending on environmental regulations and market conditions. Our plants in this group are: Portland, Shawville, Titus, Avon Lake, Gilbert, Glen Gardner, Sayreville, Werner, Mandalay and Ormond Beach and their combined open gross margin was $328 million, $474 million and $482 million during 2009, 2008 and 2007, respectively.

Restore profit This part of our fleet, representing approximately 1,600 MW, faces lower levels of profitability in the current environment. We will minimize spending, improve profitability and preserve our options for supply/demand recovery and/or improved gas-coal spreads in these plants. Our plants in this group are: Elrama, New Castle, Niles and Indian River and their combined open gross margin was $77 million, $125 million and $164 million during 2009, 2008 and 2007, respectively.

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As described above, the plants comprising each of these four groups are similarly situated particularly with regard to profitability, upside potential and our expectation of future environmental investment based on current market conditions. Therefore, we believe that presenting the amount of open gross margin for each group provides an additional way of viewing our operations and facilitates understanding of the factors and trends affecting our business. The above amounts exclude open gross margin relating to (a) our previously-owned Bighorn plant and Channelview plant ($49 million during 2007), (b) selective commercial strategies not designated to a specific plant but related more to a geographical region ($(3) million, $35 million and $39 million during 2009, 2008 and 2007, respectively) and (c) other insignificant items ($1 million, $1 million and $(2) million during 2009, 2008 and 2007, respectively). See Consolidated Results of Operations for the reconciliations of open gross margin to loss from continuing operations.

Pending Environmental Matters. We make decisions to invest in environmental capital projects based on relatively certain regulations and the expected economic returns on the capital. As discussed above, we expect future environmental investments would most likely be considered in our near-term profit/controls group of plants.

The EPA has stated that it expects to finalize a new rule to replace CAIR in 2011. Various agencies, including the EPA, are considering other regulations related to national ambient air quality standards and hazardous air pollutants. The following table lists the coal plants in our near-term profit/controls group that may be impacted by this new rule and preliminary estimates, stated in 2009 dollars, of additional investments that we could consider as a result. We expect these estimates will change as more information becomes available regarding the nature and timing of the potential investments.

	NOx Controls	SO_2 Controls	Combined
	(preliminary estimates, in millions of 2009 dollars)		
Avon Lake	$ 150	$ 280	$ 420
Portland	135	295	415
Shawville	90	235	320
Titus	85	175	255

The impact on our business of these pending regulations and whether we make any of the potential investments is uncertain and depends on the form (whether cap-and-trade or MACT), content and timing of the regulations, the effect of the regulations on wholesale power prices and allowance prices, as well as the cost of controls, profitability of our plants, market conditions at the time and the likelihood of CO_2 regulation. We may choose to not make any of the potential investments listed above.

The costs associated with more stringent environmental air quality requirements may result in coal plants, including some of ours, being retired sooner than currently contemplated. However, any such retirements could contribute to improving supply and demand fundamentals for the remaining fleet. Any resulting increased demand for gas could increase the spread between gas and coal prices, which would also benefit the remaining coal fleet.

Furthermore, the United States Congress is considering legislation that would impose mandatory limitation of CO_2 and other greenhouse gas emissions for the domestic power generation sector. State-specific or regional regulatory initiatives to stimulate CO_2 emission reductions in our industry are increasingly active. The impact on our business of these matters are uncertain and depends on the form and content of resulting regulations, including whether and to what extent allowances are allocated to us, the timing of resulting regulations and their effect on wholesale power prices and allowance prices, the profitability of our plants and market conditions at the time, as well as whether and to what extent there are cost effective control technologies or energy efficiency measures available to reduce emissions at our plants.

If CO_2 legislation or regulation transpires, we expect that the demand for gas and/or renewable sources of energy will increase over time. This could decrease economic generation at coal plants. Implementation of a CO_2 cap-and-trade program in addition to other emission control requirements could increase the likelihood of coal plant retirements.

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Given the uncertainty related to these pending environmental matters, we cannot predict the actual outcome or ultimate impact of these matters on our business. See Liquidity and Capital Resources below, Business Environmental Matters in Item 1A of this Form 10-K and note 16(b) to our consolidated financial statements for further discussion.

Effectiveness and Efficiency Measures for 2010. Consistent with our flexible plant-specific operating model, our objective is to operate each plant to capture the maximum value at the lowest economical cost over time. We plan to use total margin capture factor to measure our effectiveness of achieving this objective. Total margin capture factor is calculated by dividing open gross margin generated by the plants by the total available open gross margin assuming 100% availability. We plan to measure our efficiency of capturing margin utilizing total cost per MWh generated and total cost per MW of generation capacity. These costs metrics will include operation and maintenance expense (excluding the REMA lease expense) and general and administrative expense as well as maintenance capital expenditures.

Impairments of Long-Lived Assets. In December 2009, we evaluated each of our plants including the related intangible assets for potential impairments. We determined that two plants (New Castle and Indian River) undiscounted cash flows did not exceed the carrying value of the net property, plant and equipment and related intangible assets. Thus, we estimated each plant s fair value and determined we incurred pre-tax impairment charges of $211 million. See Management s Discussion and Analysis of Financial Condition and Results of Operations New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates in Item 7 of this Form 10-K and note 4 to our consolidated financial statements for further discussion.

Exit of Retail Business. In December 2008, we sold our Northeast retail commercial, industrial and governmental/institutional (C&I) contracts. In May 2009, we sold our Texas retail business. In December 2009, we sold our Illinois retail C&I contracts. The sale of the retail business achieved the following important strategic objectives for us:

- eliminated the need for approximately $2.0 billion of credit support and removed capital requirements associated with contingent collateral requirements, which lowered our overall risk profile

- enhanced our consolidated balance sheet and improved our liquidity position

Consolidated Results of Operations

2009 Compared to 2008 and 2008 Compared to 2007

Following the sale of our Texas retail business and commencing in the third quarter of 2009, we have four reportable segments: East Coal, East Gas, West and Other. We have presented the segment information in this report on a consistent basis for 2009, 2008 and 2007. See note 20 to our consolidated financial statements.

Our income/loss from continuing operations before income taxes for 2009 compared to 2008 changed by $630 million (income in 2008 of $26 million compared to loss in 2009 of $604 million) primarily due to (a) open gross margin, which decreased by $430 million due to open energy unit margins declining $16/MWh driven by weak commodity prices, weak economic conditions and mild summer and early winter weather and (b) hedges and other items, which changed by $385 million primarily due to out-of-the money coal hedges in 2009 compared to in-the-money coal hedges in 2008. These items were partially offset by (a) the difference between the goodwill impairment of $305 million in 2008 and the long-lived assets impairments of $211 million in 2009 and (b) $45 million of lower operation and maintenance expense primarily attributable to the use of our plant-specific operating model.

Our income/loss from continuing operations before income taxes for 2008 compared to 2007 changed by $388 million (loss in 2007 of $362 million compared to income in 2008 of $26 million) primarily due to (a) hedges and other items, which changed by $337 million primarily due to in-the-money coal hedges in 2008 and lower losses on our closed power hedges, (b) debt extinguishments losses decreased by $112 million, (c) $110 million decrease in interest expense and operation and maintenance expense and (d) $85 million

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decrease in depreciation and amortization. These items were partially offset by the goodwill impairment in 2008 of $305 million.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
East Coal open gross margin[1]	$ 425	$ 858	$ 848	$ (433)	$ 10
East Gas open gross margin[1]	208	187	159	21	28
West open gross margin[1]	133	166	161	(33)	5
Other open gross margin[1]	60	45	91	15	(46)
Total[2]	826	1,256	1,259	(430)	(3)
Hedges and other items	(152)	233	(104)	(385)	337
Unrealized gains (losses) on energy derivatives	22	(9)	7	31	(16)
Operation and maintenance	(550)	(595)	(643)	45	48
General and administrative	(101)	(122)	(135)	21	13
Western states litigation and similar settlements		(37)	(22)	37	(15)
Gains on sales of assets and emission and exchange allowances, net	22	93	26	(71)	67
Goodwill and long-lived assets impairments	(211)	(305)		94	(305)
Depreciation and amortization	(269)	(313)	(398)	44	85
Income of equity investment, net	1	1	5		(4)
Debt extinguishments losses	(8)	(2)	(114)	(6)	112
Other, net		5		(5)	5
Interest expense	(186)	(200)	(262)	14	62
Interest income	2	21	19	(19)	2
Income tax (expense) benefit	125	(136)	160	261	(296)
Loss from continuing operations	(479)	(110)	(202)	(369)	92
Income (loss) from discontinued operations	882	(630)	567	1,512	(1,197)
Net income (loss)	$ 403	$ (740)	$ 365	$ 1,143	$ (1,105)

(1) Represents our segment profitability measure.

(2) See Business Overview for open gross margin by our plant-specific operating model groups.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
Diluted Earnings (Loss) per Share					
Loss from continuing operations	$ (1.36)	$ (0.32)	$ (0.59)	$ (1.04)	$ 0.27

Income (loss) from discontinued operations		2.51		(1.81)		1.66		4.32		(3.47)
Net income (loss)	$	1.15	$	(2.13)	$	1.07	$	3.28	$	(3.20)

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Revenues.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Third-party revenues	$ 1,869	$ 3,142	$ 3,044	$ (1,273)[(1)]	$ 98[(2)]
Revenues affiliates		253[(3)]	127[(3)]	(253)	126
Unrealized gains (losses) on energy derivatives	(44)	(1)	32	(43)[(4)]	(33)[(5)]
Total revenues	$ 1,825	$ 3,394	$ 3,203	$ (1,569)	$ 191

(1) Decrease primarily due to (a) lower power and natural gas sales prices and (b) lower power sales volumes. These decreases were partially offset by an increase in natural gas sales volumes.

(2) Increase primarily due to (a) higher power and natural gas sales prices and (b) higher capacity payments. These increases were partially offset by (a) lower natural gas and power sales volumes and (b) lower steam sales due to the deconsolidation of Channelview.

(3) We deconsolidated Channelview in August 2007. These revenues represent sales of fuel to Channelview prior to the assets being sold in July 2008.

(4) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

(5) See footnote 2 under Unrealized Gains (Losses) on Energy Derivatives.

Cost of Sales.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Third-party costs	$ 1,195	$ 1,834	$ 1,973	$ (639)[(1)]	$ (139)[(2)]
Cost of sales affiliates		72[(3)]	43[(3)]	(72)	29
Unrealized (gains) losses on energy derivatives	(66)	8	25	(74)[(4)]	(17)[(5)]
Total cost of sales	$ 1,129	$ 1,914	$ 2,041	$ (785)	$ (127)

(1) Decrease primarily due to (a) lower prices paid for natural gas and (b) lower natural gas and coal volumes purchased. These decreases were partially offset by higher prices paid for coal.

(2) Decrease primarily due to lower natural gas volumes purchased. This decrease was partially offset by higher prices paid for natural gas and coal.

(3) We deconsolidated Channelview in August 2007. These cost of sales represent purchases of power from Channelview prior to the assets being sold in July 2008.

(4) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

(5) See footnote 2 under Unrealized Gains (Losses) on Energy Derivatives.

Open Gross Margin. Our segment profitability measure is open gross margin. Open gross margin consists of (a) open energy gross margin and (b) other margin. Open gross margin excludes hedges and other items and unrealized gains/losses on energy derivatives. Open energy gross margin is calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs. Open energy gross margin is (a)(i) economic generation multiplied by (ii) commercial capacity factor (which equals generation) multiplied by (b) open energy unit margin. Economic generation is estimated generation at 100% plant availability based on an hourly analysis of when it is economical to generate based on the price of power, fuel, emission allowances and variable operating costs. Economic generation can vary depending on the comparison of market prices to our cost of generation. It will decrease if there are fewer hours when market prices exceed the cost of generation. It will increase if there are more hours when market prices exceed the cost of generation. Other margin represents power purchase agreements, capacity payments, ancillary services revenues and selective commercial strategies relating to optimizing our assets.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
East Coal					
Open energy gross margin	$ 239	$ 719	$ 778	$ (480)(1)	$ (59)(2)
Other margin	186	139	70	47(3)	69(4)
Open gross margin	$ 425	$ 858	$ 848	$ (433)	$ 10
East Gas					
Open energy gross margin	$ 20	$ 42	$ 50	$ (22)(5)	$ (8)
Other margin	188	145	109	43(4)	36(6)
Open gross margin	$ 208	$ 187	$ 159	$ 21	$ 28
West					
Open energy gross margin	$ 14	$ (1)	$ 20	$ 15(7)	$ (21)(8)
Other margin	119	167	141	(48)(9)	26(10)
Open gross margin	$ 133	$ 166	$ 161	$ (33)	$ 5
Other					
Open energy gross margin	$	$ 1	$ 24	$ (1)	$ (23)(11)
Other margin	60	44	67	16(12)	(23)(13)
Open gross margin	$ 60	$ 45	$ 91	$ 15	$ (46)

(1) Decrease primarily due to (a) lower unit margins (lower power prices partially offset by lower fuel costs) and (b) lower economic generation.

(2) Decrease primarily due to (a) lower economic generation and (b) lower unit margins (higher fuel costs partially offset by higher power prices). These decreases were partially offset by increased commercial capacity factor due to lower planned and unplanned outages in 2008.

(3) Increase primarily due to higher RPM capacity payments. This increase was partially offset by lower ancillary payments.

(4) Increase primarily due to higher RPM capacity payments.

(5) Decrease primarily due to lower unit margins (lower power prices partially offset by lower fuel costs). This decrease was partially offset by higher economic generation.

(6) Increase primarily due to higher RPM capacity payments. This increase was partially offset by lower revenue from purchase power agreements.

(7) Increase primarily due to higher unit margins (lower fuel costs). This increase was partially offset by lower economic generation.

(8) Decrease primarily due to (a) lower unit margins (higher fuel costs partially offset by higher power prices) and (b) lower economic generation.

(9) Decrease primarily due to selective commercial strategies, which we did not engage in during 2009.

(10) Increase primarily due to higher capacity payments.

(11) Decrease primarily due to lower economic generation related to the deconsolidation of Channelview in August 2007.

(12) Increase primarily due to (a) higher revenue from power purchase agreements and (b) selective commercial strategies, which we did not engage in during 2009.

(13) Decrease primarily due to (a) the deconsolidation of Channelview in August 2007 and (b) selective commercial strategies, which we did not engage in during 2009.

Included in revenues or cost of sales are two items (a) hedges and other items and (b) unrealized gains/losses on energy derivatives that are not included in open gross margin. See notes 2(e), 6 and 20 to our consolidated financial statements for further discussion. The analyses of these items are included below.

Hedges and Other Items. We may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. Hedges and other items primarily relate to settlements of power and fuel hedges, long-term natural gas transportation contracts, storage contracts and long-term tolling contracts. They are primarily derived based on methodology consistent with the calculation of open energy gross margin in that a portion of this item represents the difference between the margins calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs and the actual amounts paid or received during the period.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
Hedges and other items income (loss)	$ (152)	$ 233	$ (104)	$ (385)(1)	$ 337(2)

(1) Net change primarily due to (a) $482 million decrease due to a decline in results of fuel hedges and sales of excess coal supplies in 2009 as compared to 2008 in our East Coal segment and (b) $60 million decrease due to a decline on gas transportation hedges. These decreases were partially offset by (a) $97 million gain on hedges of generation, (b) $29 million decrease in losses on closed power hedges and (c) $19 million lower market valuation adjustments to fuel inventory due to $19 million in losses in 2009 in our East Coal segment and $38 million in losses in 2008 in our East Gas and Other segments.

(2) Net change primarily due to (a) $191 million increase in gains on fuel hedges and (b) $137 million decrease in losses on closed power hedges.

Unrealized Gains (Losses) on Energy Derivatives. We use derivative instruments to manage operational or market constraints and to increase the return on our generation assets. We record in our consolidated statement of operations non-cash gains/losses based on current changes in forward commodity prices for derivative instruments receiving mark-to-market accounting treatment which will settle in future periods. We refer to these gains and losses prior to settlement, as well as ineffectiveness on cash flow hedges, as unrealized gains/losses on energy derivatives. In some cases, the underlying transactions being economically hedged receive accrual accounting treatment, resulting in a mismatch of accounting treatments. Since the application of mark-to-market accounting has the effect of pulling forward into current periods non-cash gains/losses relating to and reversing in future delivery periods, analysis of results of operations from one period to another can be difficult.

Change **Change**

	2009	2008	2007	from 2008 to 2009	from 2007 to 2008
Revenues unrealized	$ (44)	$ (1)	$ 32	$ (43)	$ (33)
Cost of sales unrealized	66	(8)	(25)	74	17
Net unrealized gains (losses) on energy derivatives	$ 22	$ (9)	$ 7	$ 31(1)	$ (16)(2)

(1) Net change primarily due to $61 million in gains due to reversal of previously recognized unrealized losses on energy derivatives which settled during the period, partially offset by $30 million in losses from changes in prices on our energy derivatives marked to market.

(2) Net change primarily due to $79 million in losses due to reversal of previously recognized unrealized gains on energy derivatives which settled during the period, partially offset by $63 million in gains from changes in prices on our energy derivatives marked to market.

Operation and Maintenance.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Plant operation and maintenance	$ 395	$ 441	$ 476	$ (46)[(1)]	$ (35)[(2)]
REMA leases	60	60	60		
Taxes other than income and insurance	34	38	41	(4)	(3)
Information Technology, Risk and other salaries and benefits	25	22	21	3	1
Commercial Operations	17	20	19	(3)	1
Severance	6			6	
Bighorn (non-plant operations)		7	8	(7)[(3)]	(1)[(3)]
Channelview (non-plant operations)			8		(8)[(4)]
Other, net	13	7	10	6	(3)
Operation and maintenance	$ 550	$ 595	$ 643	$ (45)	$ (48)

(1) Decrease primarily due to (a) $22 million decrease in base O&M primarily due to decreased operations attributable to the use of our plant-specific operating model and cost reduction initiatives and (b) $13 million decrease in outages and projects spending. These decreases were primarily in our East Coal segment.

(2) Decrease primarily due to (a) $15 million decrease in planned outages and projects largely driven by decreases in our East Coal segment, (b) the deconsolidation of Channelview (which was part of our Other segment) in August 2007 and (c) $6 million decrease in base O&M due to decreased routine maintenance largely driven by decreases in our East Coal segment partially offset by increases in our West segment.

(3) The Bighorn plant was sold in October 2008.

(4) We deconsolidated Channelview in August 2007 and sold the plant in July 2008.

General and Administrative.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Salaries and benefits	$ 53	$ 59	$ 64	$ (6)	$ (5)
	21	29	36	(8)	(7)

Professional fees, contract services and information systems maintenance					
Rent and utilities	13	15	14	(2)	1
Legal costs	5	8	9	(3)	(1)
Severance	3		1	3	(1)
Other, net	6	11	11	(5)	
General and administrative	$ 101	$ 122	$ 135	$ (21)	$ (13)

Western States Litigation and Similar Settlements. See notes 16 and 17 to our consolidated financial statements.

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Gains on Sales of Assets and Emission and Exchange Allowances, Net.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
CO_2 exchange allowances[1]	$ 10	$ 38	$	$ (28)	$ 38
SO_2 and NO_x emission allowances	7		1	7	(1)
Bighorn plant[2]	3	47		(44)	47
Investment in and receivables from Channelview[3]	2	6		(4)	6
Equipment			24		(24)
Other, net		2	1	(2)	1
Gains on sales of assets and emission and exchange allowances, net	$ 22	$ 93	$ 26	$ (71)	$ 67

(1) During 2007, we joined the Chicago Climate Exchange and sold some allowances in 2008 and 2009.

(2) The Bighorn plant was in our West segment and sold in October 2008.

(3) In July 2008, we sold the Channelview plant, which was in our Other segment. This amount represents our change in the estimate of the recovery of the net investment in and receivables from Channelview as it was deconsolidated in August 2007.

Goodwill Impairment. See note 5 to our consolidated financial statements.

Long-lived Assets Impairments. See note 4 to our consolidated financial statements.

Depreciation and Amortization.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Depreciation on plants	$ 226	$ 226	$ 269	$	$ (43)[1]
Other, net depreciation	15	15	14		1
Depreciation	241	241	283		(42)
Amortization of emission allowances	24	68	110	(44)[2]	(42)[3]
Other, net amortization	4	4	5		(1)

Amortization	28	72	115	(44)	(43)
Depreciation and amortization	$ 269	$ 313	$ 398	$ (44)	$ (85)

(1) Decrease primarily due to (a) early retirements of plant components when replacement components are installed for upgrades (from $29 million, primarily in our East Coal and East Gas segments, in 2007 to $4 million in 2008), (b) classification of Bighorn assets (which were in our West segment) as held for sale in April 2008, which requires depreciation to cease and (c) the deconsolidation of Channelview in August 2007.

(2) Decrease primarily due to (a) lower weighted average cost of SO_2 allowances and (b) decrease in SO_2 allowances used. The decrease was primarily in our East Coal segment.

(3) Decrease primarily due to (a) lower weighted average cost of SO_2 allowances and (b) decrease in SO_2 and NO_x allowances used. The decrease was primarily in our East Coal segment.

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Income of Equity Investment, Net.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Sabine Cogen, LP	$ 1	$ 1	$ 5	$	$ (4)
Income of equity investment, net	$ 1	$ 1	$ 5	$	$ (4)

Debt Extinguishments Losses.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Deferred financing costs accelerated amortization due to extinguishments	$ (5)	$ (1)	$ (41)	$ (4)	$ 40
Net premium/discount debt extinguishments losses	(3)	(1)	(73)(1)	(2)	72
Debt extinguishments losses	$ (8)	$ (2)	$ (114)	$ (6)	$ 112

(1) Includes $21 million consent solicitation fee.

Other, Net.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Impairment of investments	$	$ (2)	$ (3)	$ 2	$ 1
Other, net		7	3	(7)(1)	4
Other, net	$	$ 5	$	$ (5)	$ 5

(1) Decrease primarily due to a recovery of a claim in 2008.

Interest Expense.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Fixed-rate debt	$ 206	$ 212	$ 219	$ (6)	$ (7)
Deferred financing costs	7	7	9		(2)
Financing fees expensed	6	8	12	(2)	(4)
Channelview			16		(16)[1]
Variable-rate debt			14		(14)
Amortization of fair value adjustment of acquired debt	(12)	(11)	(11)	(1)	
Capitalized interest[2]	(23)	(17)	(4)	(6)	(13)
Other, net	2	1	7	1	(6)
Interest expense[3]	$ 186	$ 200	$ 262	$ (14)	$ (62)

(1) Decrease due to the deconsolidation of Channelview in August 2007.

(2) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick and Keystone plants, which are included in our East Coal segment.

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(3) See notes 7 and 23 to our consolidated financial statements regarding certain debt and related interest expense classified in discontinued operations.

Interest Income.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Interest on temporary cash investments	$ 2	$ 15	$ 12	$ (13)[1]	$ 3
Net margin deposits		2	6	(2)	(4)
Other, net		4	1	(4)	3
Interest income	$ 2	$ 21	$ 19	$ (19)	$ 2

(1) Decrease primarily due to significant reduction in money market interest rates.

Income Tax Expense (Benefit). See note 14 to our consolidated financial statements. A reconciliation of the federal statutory income tax rate to the effective income tax rate is:

	2009	2008	2007
Federal statutory rate	(35)%	35%	(35)%
Additions (reductions) resulting from:			
Federal tax uncertainties		2	(2)
Federal valuation allowance	16	67	(7)
State income taxes, net of federal income taxes	(1)[1]	180(2)	(4)
Goodwill impairment		201	
Other, net	(1)	35(3)	4
Effective rate	(21)%	520%	(44)%

(1) Of this percentage, $32 million (5%) relates to an increase in our state valuation allowances.

(2) Of this percentage, $36 million (142%) relates to an increase in our state valuation allowances.

(3) Of this percentage, $6 million (23%) relates to write-off of book goodwill due to the sale of our Bighorn plant in October 2008.

Income (Loss) from Discontinued Operations. See note 23 to our consolidated financial statements.

Liquidity and Capital Resources

Overview. We are committed to a strong balance sheet and ample liquidity that will enable us to avoid distress in cyclical troughs and access capital markets throughout the cycle. We believe our liquidity has and continues to exceed the level required to achieve this goal. As discussed below, we have used and expect to continue to use some of our cash and cash equivalents to reduce debt. In late 2009, we deployed some of our cash to margin deposits by replacing outstanding letters of credit, which together with our reduction of secured debt, improved our revolver s financial maintenance covenant ratio.

Debt Reduction. Our goal for gross debt (total GAAP debt plus our REMA operating leases) is $1.25 billion to $1.75 billion. As of December 31, 2009, we had gross debt of $2.8 billion and GAAP debt of $2.4 billion. The comparable target for total GAAP debt, based on the current balance for our REMA leases of $423 million, is approximately $800 million to $1.3 billion. We believe that the non-GAAP measure gross debt is a useful and relevant measure of our financial obligations and the strength and flexibility of our capital structure.

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On May 1, 2009, we sold our Texas retail business for $363 million in cash, which included the value of the net working capital. We offered a portion of the net proceeds to holders of our senior secured notes and PEDFA bonds. The following table reflects our 2009 debt reduction efforts.

	Senior Secured 6.75% Notes	PEDFA Fixed-Rate Bonds (in millions)	Total
Net proceeds from sale of Texas retail	$ 169	$ 92	$ 261(1)
Tender offer	127	2	129(2)
Open market purchases	92	35	127(3)
Total	$ 388	$ 129	$ 517

(1) Purchased at par and all activity is classified as discontinued operations.

(2) Total consideration paid was $132 million.

(3) Total consideration paid was $127 million.

In the future, we could use a variety of means to achieve our gross debt goal, including retirements at maturity (Orion Power Holdings, Inc. s $400 million senior unsecured notes due in May 2010), open market purchases, call provisions and tender offers.

Cash Flows. During 2009, we used $392 million in operating cash flows from continuing operations, including the net increase in margin deposits of $256 million (cash outflow). See Historical Cash Flows for further detail of our cash flows from operating activities and explanation of our $158 million and $248 million use of cash from investing activities from continuing operations and use of cash from financing activities from continuing operations, respectively, during 2009.

Sources of Liquidity and Capital Resources

Our principal sources of liquidity and capital resources are cash and cash equivalents on hand, cash flows from operations, unused borrowing capacity and letters of credit capacity. We expect these sources will be adequate to meet our liquidity needs in 2010.

As of February 11, 2010, we had total available liquidity of $1.7 billion, comprised of cash and cash equivalents ($1.0 billion), unused borrowing capacity ($500 million) and letters of credit capacity ($169 million).

As discussed under Business Overview Strategy, our current market environment is challenged. Commodity prices and power demand were down in 2009 and remain low relative to recent history. However, we have fixed commitments to receive RPM capacity payments through May 2013 and power purchase and capacity agreement payments through 2014 totaling $1.8 billion, of which $555 million relates to 2010. See note 15 to our consolidated financial statements. See Business Operations in Item 1 of this Form 10-K for revenues by type and by reportable segment for 2009, 2008 and 2007.

We continue to monitor our business and hedging with the goal of at least breaking even on a free cash flow basis in the event of a sustained depressed commodity price environment. Based on our assessment of the economic environment and volatility in commodity markets, we have hedged, with swaps, approximately 33% and 31% of estimated power generation from our PJM coal plants (which are in our East Coal segment) for 2010 and 2011 (based on MWh), respectively. We have hedged an additional 1% and 7% of this estimated power generation for 2010 and 2011, respectively, with financial options to retain the energy margin upside for market improvements. We consider free cash flow to be operating cash flow from continuing operations, adjusted for capital expenditures, net sales (purchases) of emission and exchange allowances and changes in net margin deposits.

If additional liquidity is required, it could be sourced from collateral structures, borrowings, net proceeds from asset sales or securities offerings. We cannot make any assurances that we would be able to obtain such additional liquidity on commercially reasonable terms or at all. Also, as discussed in note 7 to our consolidated

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financial statements, there are certain restrictive covenants and other contractual restrictions related to our ability to obtain additional borrowings.

For further description of factors that could affect our liquidity and capital resources, see Risk Factors in Item 1A of this Form 10-K and the discussion of restrictive covenants in note 7 to our consolidated financial statements.

Liquidity and Capital Requirements

Our liquidity and capital requirements primarily reflect our operating costs, capital expenditures (including environmental capital expenditures), collateral requirements, purchases of emissions allowances, discretionary debt extinguishments and debt service. Examples of operating costs include purchases of fuel, plant maintenance costs and payroll costs. Costs associated with litigation, regulatory and tax proceedings can also have a significant impact on our liquidity and cash requirements. For settlements and other costs associated with litigation, regulatory and tax proceedings, see notes 14, 16 and 17 to our consolidated financial statements.

Capital Requirements. The following table provides information about our actual and estimated future capital requirements:

	2009 Actual	2010 Estimated (in millions)	2011 Estimated
Maintenance capital expenditures(1)	$ 56	$ 48	$ 42
Environmental(2)(3)	111	34	20
Capitalized interest	23(4)	6	
Total capital expenditures	$ 190	$ 88	$ 62

(1) Excludes $8 million for 2010 through 2014 for pre-existing environmental conditions and remediation, which have been accrued for in our consolidated balance sheet as of December 31, 2009.

(2) For a discussion of pending and contingent matters related to environmental regulations, see Business Overview Pending Environmental Matters, note 16(b) to our consolidated financial statements and Business Environmental Matters in Item 1 of this Form 10-K.

(3) The environmental amounts for years beyond 2011 could significantly increase subject to finalization of rules and market conditions.

(4) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick and Keystone plants.

Contractual Obligations. The following table includes our obligations and commitments to make future payments under contracts as of December 31, 2009:

	Less than	One to	Three to

Contractual Obligations	Total	One Year	Three Years	Five Years	More than Five Years
			(in millions)		
Debt, including credit facilities[1]	$ 3,770	$ 569	$ 290	$ 1,122	$ 1,789
Other commodity commitments[2]	972	229	204	139	400
Derivative liabilities	213	152	61		
REMA operating lease payments	934	52	119	128	635
Maintenance agreements obligations	505	31	22	35	417
Other operating lease payments	309	64	98	50	97
Plant and equipment commitments[3]	53	31	7	15	
Other[4]	291	147	31	31	82
Total contractual cash obligations	$ 7,047	$ 1,275	$ 832	$ 1,520	$ 3,420

(1) Includes interest payments.

(2) See note 15(c) to our consolidated financial statements.

(3) These amounts are included in the capital requirements table above under either maintenance capital expenditures or environmental.

(4) Includes an estimated income tax cash payment of $65 million relating to Western states-related matters, estimated pension and post retirement benefit payments and other contractual obligations.

As of December 31, 2009, we have estimated minimum sales commitments over the next five years, which are not classified as derivative assets and liabilities, of (in millions):

2010	$ 555
2011	474
2012	440
2013	198
2014	100
Total[(1)]	$ 1,767

(1) See note 15(c) to our consolidated financial statements.

Contingencies and Guarantees. We are involved in a number of legal, environmental, tax and other proceedings before courts and are subject to ongoing investigations by certain governmental agencies that could negatively impact our liquidity. See notes 16 and 17 to our consolidated financial statements.

We also enter into guarantee and indemnification arrangements in the normal course of business, none of which is expected to materially impact our liquidity. See note 15(b) to our consolidated financial statements.

Credit Risk

By extending credit to our counterparties, we are exposed to credit risk. For a discussion of our credit risk and policy, see note 2(f) to our consolidated financial statements.

Off-Balance Sheet Arrangements

For 2007, 2008 and 2009, we do not have any off-balance sheet arrangements to report under requirements effective prior to 2010. In connection with related amended accounting guidance for variable interest entities, which is effective as of January 1, 2010, we are assessing (a) our REMA leases for our interests in the Conemaugh, Keystone and Shawville plants (see note 15(a) to our consolidated financial statements) and (b) the tolling agreement at the Vandolah plant whereby we provide our own fuel for operations and take all the power generated (see note 15(a) to our consolidated financial statements). If (a) the single power plant legal entities, which own the plants or our interests in the plants are determined to be variable interest entities, (b) our contracts are determined to be or contain variable interests in those entities and (c) we have the power to direct the activities of the entities that most significantly impact the entities economic performance and the obligation to absorb losses of or the right to receive benefits from the entities that could be significant to the entities, we would be required to consolidate the entities, which could materially change our future financial statements.

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Historical Cash Flows

Cash Flows Operating Activities

2009 Compared to 2008 and 2008 Compared to 2007.

	2009	2008	2007 (in millions)	Change from 2008 to 2009	Change from 2007 to 2008
Operating income (loss)	$ (413)	$ 201	$ (10)	$ (614)	$ 211
Goodwill and long-lived assets impairments	211	305		(94)	305
Depreciation and amortization	269	313	398	(44)	(85)
Gains on sales of assets and emission and exchange allowances, net	(22)	(93)	(26)	71	(67)
Net changes in energy derivatives	(21)[1]	9[2]	(7)[3]	(30)	16
Western states litigation and similar settlements		3[4]	[5]	(3)	3
Western states litigation and similar settlements payments	(3)	[4]	(35)[5][6]	(3)	35
Margin deposits, net	(256)	199	286	(455)	(87)
Option premiums purchased	(30)			(30)	
Interest payments	(194)	(206)	(300)	12	94
Change in accounts and notes receivable and accounts payable, net	96	(38)	(60)	134	22
Change in inventory	(15)	(32)	(22)	17	(10)
Income tax payments, net of refunds	(2)	(12)	(3)	10	(9)
Pension contributions	(20)	(6)	(13)	(14)	7
Kern refund[7]	3	30		(27)	30
Other, net	5	31	(4)	(26)	35
Net cash provided by (used in) continuing operations from operating activities	(392)	704	204	(1,096)	500
Net cash provided by (used in) discontinued operations from operating activities	585	(521)	558	1,106	(1,079)
Net cash provided by operating activities	$ 193	$ 183	$ 762	$ 10	$ (579)

(1) Includes unrealized gains on energy derivatives of $22 million.

(2) Includes unrealized losses on energy derivatives of $9 million.

(3) Includes unrealized gains on energy derivatives of $7 million.

(4) We expensed $37 million and paid $34 million in 2008.

(5) We expensed and paid $22 million in 2007.

(6) We expensed $35 million in 2006 and paid it in 2007.

(7) See note 16(c) to our consolidated financial statements.

Cash Flows Investing Activities

2009 Compared to 2008 and 2008 Compared to 2007.

	2009	2008	2007	Change from 2008 to 2009	Change from 2007 to 2008
			(in millions)		
Capital expenditures[1]	$ (190)	$ (279)	$ (175)	$ 89	$ (104)
Proceeds from sales of assets, net	36	527	82	(491)	445
Proceeds from sales of emission and exchange allowances	19	42[2]	7	(23)	35
Purchases of emission allowances	(22)	(61)[3]	(92)[4]	39	31
Restricted cash	(5)	1	(6)	(6)	7
Other, net	4	6	6	(2)	
Net cash provided by (used in) continuing operations from investing activities	(158)	236	(178)	(394)	414
Net cash provided by (used in) discontinued operations from investing activities	312	(20)	(1)	332	(19)
Net cash provided by (used in) investing activities	$ 154	$ 216	$ (179)	$ (62)	$ 395

(1) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick and Keystone plants, which are included in our East Coal segment. The scrubber project for our Keystone plant was completed in 2009. The scrubber project for our Cheswick plant was halted in mid-2009 with plans to resume in 2010.

(2) Includes $38 million from sales of CO_2 exchange allowances.

(3) Includes $48 million and $13 million for purchases of SO_2 and NO_x allowances, respectively.

(4) Includes $89 million for purchases of SO_2 allowances.

Cash Flows Financing Activities

2009 Compared to 2008 and 2008 Compared to 2007.

Change from 2008	Change from 2007

	2009	2008	2007	to 2009	to 2008
			(in millions)		
Proceeds from issuance of senior unsecured notes	$	$	$ 1,300	$	$ (1,300)
Payments of senior secured notes and PEDFA fixed-rate bonds	(255)	(58)	(1,126)	(197)	1,068
Net payments on senior secured term loans			(400)		400
Proceeds from issuances of stock	12	14	41	(2)	(27)
Payments of debt extinguishments expenses	(5)	(1)	(73)	(4)	72
Payments of financing costs			(31)		31
Other, net			(3)		3
Net cash used in continuing operations from financing activities	(248)	(45)	(292)	(203)	247
Net cash used in discontinued operations from financing activities	(261)			(261)	
Net cash used in financing activities	$ (509)	$ (45)	$ (292)	$ (464)	$ 247

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

See note 2 to our consolidated financial statements.

Significant Accounting Policies

See note 2 to our consolidated financial statements.

Critical Accounting Estimates

We make a number of estimates and judgments in preparing our consolidated financial statements. These estimates can differ from actual results and have a significant impact on our recorded assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We consider an estimate to be a critical accounting estimate if it requires a high level of subjectivity or judgment and a significant change in the estimate would have a material impact on our financial condition or results of operations. Each critical accounting estimate affects our four reportable segments, East Coal, East Gas, West and Other, unless indicated otherwise. However, as the impacts from our critical accounting estimates to our statements of operations are typically not included as a component of open gross margin, they do not typically impact our segments profitability measure. The Audit Committee of our Board of Directors reviews each critical accounting estimate with our senior management. Further discussion of these accounting policies and estimates is in the notes to our consolidated financial statements.

Long-Lived Assets.

We consider the estimate used to assess the recoverability of our long-lived assets (property, plant and equipment and intangible assets) a critical accounting estimate. As of December 31, 2009, we had $4.9 billion of long-lived assets. This estimate affects all segments, which hold 99% of our total net property, plant and equipment and net intangible assets. Our East Coal segment holds the largest portion of our net property, plant and equipment and net intangible assets at 59% of our consolidated total. See notes 2(g), 4 and 5 to our consolidated financial statements.

We evaluate our long-lived assets when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Examples of such events or changes in circumstances are:

- a significant decrease in the market price of a long-lived asset
- a significant adverse change in the manner an asset is being used or its physical condition
- an adverse action by a regulator or legislature or an adverse change in the business climate
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset
- a current-period loss combined with a history of losses or the projections of future losses
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life

When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. Each plant (including its property, plant and equipment and intangible assets) was determined to be its own group.

The determination of impairment is a two-step process, the first of which involves comparing the undiscounted cash flows to the carrying value of the asset. If the carrying value exceeds the undiscounted cash flows, the fair value of the asset must be determined. The fair value of an asset is the price that would be received from a sale of the asset in an orderly transaction between market participants at the measurement

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date. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, when available. In the absence of quoted prices for identical or similar assets, fair value is estimated using various internal and external valuation methods. These methods include discounted cash flow analyses and reviewing available information on comparable transactions.

Key Assumptions. The following summarizes some of the most significant estimates and assumptions used in evaluating our plant level undiscounted cash flows. The ranges for the fundamental view assumptions are to account for variability by year and region.

	December 31, 2009
Undiscounted Cash Flow Scenarios Weightings:	
5-year market forecast with escalation(1)(2)	50%
5-year market forecast with fundamental view(1)	50%
Range of Assumptions in Fundamental View:	
Demand for power growth per year	1%-2%
After-tax rate of return on new construction(3)	6.5%-9.5%
Spread between natural gas and coal prices, $/MMBTU(4)	$3-$5

(1) For each scenario, the first five years of cash flows are the same.

(2) We assumed an annual 2.5% escalation percentage beyond year five.

(3) The low to mid part of the range represents natural gas-fired plants required returns and the mid to high part of the range represents coal-fired and nuclear plants required returns.

(4) Natural gas and coal prices are prior to transportation costs.

Our Indian River plant is located in Florida where the merchant power market is primarily bilateral. This plant had historically generated most of its revenues and gross margin from power purchase agreements, which expired in 2009. Therefore, we believed it was more meaningful to develop different assumptions for our Indian River plant. We estimated the cash flows and probability weightings around five different scenarios. Four of the scenarios (weighted for a combined 70%) included power purchase agreements for varying time periods and ultimate sale of the plant and the remaining scenario (weighted at 30%) included a sale only.

We estimate the undiscounted cash flows of our plants based on a number of subjective factors, including: (a) appropriate weighting of undiscounted cash flow scenarios, as shown in the table above, (b) forecasts of future power generation margins, (c) estimates of our future cost structure, (d) environmental assumptions, (e) time horizon of cash flow forecasts and (f) estimates of terminal values of plants, if necessary, from the eventual disposition of the assets. We did not include the cash flows associated with our economic hedges in our PJM region (East Coal and East Gas segments) as these cash flows are not specific to any one plant.

Under the 5-year market forecast with escalation scenario, we use the following data: (a) forward market curves for commodity prices as of December 18, 2009 for the first five years, (b) cash flow projections through the plant s estimated remaining useful life and (c) escalation factor of cash flows of 2.5% per year after year five.

Under the 5-year market forecast with fundamental view scenario, we model all of our plants and those of others in the regions in which we operate using these assumptions: (a) forward market curves for commodity prices as of December 18, 2009 for the first five years; (b) ranges shown in the table above used in developing our fundamental view beyond five years; (c) the markets in which we operate will continue to be deregulated and earn margins based on forward or projected market prices; (d) projected market prices for energy and capacity will be set by the forecasted available supply and level of forecasted demand new supply will enter markets when market prices and associated returns, including any assumed subsidies for renewable energy, are sufficient to achieve minimum return requirements; (e) minimum return requirements on future construction of new generation facilities, as shown in the table above, will likely be driven or influenced by utilities, which we expect will have a lower cost of capital than merchant generators; (f) various ranges of

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environmental regulations, including those for SO_2, NO_x and greenhouse gas emissions; and (g) cash flow projections through the plant s estimated remaining useful life.

Fair Value. Generally, fair value will be determined using an income approach or a market-based approach. Under the income approach, the future cash flows are estimated as described above and then discounted using a risk-adjusted rate. Under a market-based approach, we may also consider prices of similar assets, consult with brokers or employ other valuation techniques.

The following are key assumptions used in our fair value analyses for our two plants for which the undiscounted cash flows did not exceed the net book value of the long-lived assets.

	New Castle	**Indian River**
Valuation approach weightings:		
Income approach	100%	100%
Market-based approach	0%	0%
Risk-adjusted discount rate for the estimated cash flows	15%	15%

We only used the income approach as we believe no relevant market data exists for these two plants for which we were required to estimate fair value. The discount rates reflect the uncertainty of the plants cash flows and their inability to support meaningful amounts of debt, and was determined considering factors such as the potential for future capacity and power purchase agreement revenues and regulatory, commodity and macroeconomic conditions.

We determined that our New Castle plant, which consists of property, plant and equipment, was impaired by $120 million as of December 31, 2009. This impairment was primarily due to the expected levels of low profitability given that the plant would likely require significant environmental capital expenditures in the future under existing and likely environmental regulations. Under the plant-specific operating model, the New Castle plant is in the restore profit group. We determined that our Indian River plant, which consists of property, plant and equipment and various intangible assets (water rights, permits and emission allowances), was impaired by $91 million as of December 31, 2009. This impairment was primarily due to a power purchase agreement with a utility in Florida expiring in December 2009 and because of the uncertainty that a replacement power purchase agreement will occur for the foreseeable future. Under the plant-specific operating model, the Indian River plant is in the restore profit group. See Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K for further discussion of our plant-specific operating model. We believe the remaining net book values of $44 million for New Castle and $52 million for Indian River represent our best estimates of fair values as of December 31, 2009.

Certain disclosures are required about nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. This applies to our long-lived assets for which we were required to determine fair value. A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. See note 2(d) to our consolidated financial statements for further discussion about the three levels. These assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and affects the valuation of fair value and the assets placement within the fair value hierarchy levels.

	December 31,	**2009**

	2009			Impairment
	Level 1	Level 2	Level 3	Charges
		(in millions)		
New Castle property, plant and equipment[(1)]	$	$	$ 44	$ 120
Indian River property, plant and equipment, water rights, permits and emission allowances[(2)]			52	91
Total	$	$	$ 96	$ 211

40

(1) New Castle is in our East Coal segment.

(2) Indian River is in our Other segment.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether long-lived assets are recoverable or whether impairment exists are subject to high degree of uncertainty. Different assumptions as to power prices, fuel costs, our future cost structure, environmental assumptions and remaining useful lives and ultimate disposition values of our plants would result in estimated future cash flows that could be materially different than those considered in the recoverability assessments as of December 31, 2009 and could result in having to estimate the fair value of other plants.

Use of a different risk-adjusted discount rate would result in fair value estimates for the two plants for which we recorded an impairment in 2009 that could be materially greater than or less than the fair value estimates as of December 31, 2009. Any future fair value estimates for our New Castle and Indian River long-lived assets that are greater than the fair value estimates as of December 31, 2009 will not result in reversal of the 2009 impairment charges.

The undiscounted cash flow scenarios we considered in assessing the recoverability of our long-lived assets are those which we believe are most likely to occur based on market data as of the end of 2009. If we had solely utilized the 5-year market forecast with escalation scenario, the carrying value of four additional plants and related intangible assets ($628 million) would have been greater than the undiscounted cash flows, which would have necessitated fair value estimates for those plants. Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the carrying value of one additional plant and related intangible assets ($110 million) would have been greater than the undiscounted future cash flows, which would have necessitated fair value estimates for that plant.

The discounted cash flow scenarios we considered in determining the fair values of our New Castle and Indian River long-lived assets are those which we believe are most representative of a market participant view. If we had solely utilized the 5-year market forecast with escalation scenario, the fair value of the New Castle long-lived assets would have been $51 million (resulting in an impairment of $113 million as opposed to $120 million recognized). Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the fair value of the New Castle long-lived assets would have been $35 million (resulting in an impairment of $129 million as opposed to $120 million recognized). As discussed above for our Indian River plant, if we had only used the two scenarios that lead to the most extreme fair values, the calculated fair value for our Indian River long-lived assets would have ranged from $25 million to $84 million (resulting in an impairment ranging from $118 million to $59 million as opposed to $91 million recognized).

Fair Value Derivative Assets and Liabilities.

In determining fair value for our derivative assets and liabilities, we generally use the 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.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Derivative instruments classified as Level 2 primarily include emission allowances futures that are exchanged-traded and over-the-counter (OTC) derivative instruments such as generic swaps, forwards and options. The fair value measurements of these derivative assets and liabilities are based largely on unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. Derivative instruments for which fair value is calculated using quoted prices that are deemed not active or that have been extrapolated from quoted prices in active markets are classified as Level 3. For certain natural gas and power contracts, we adjust seasonal or calendar year quoted prices based on historical observations to represent fair value for each month in the season or calendar year, such that the average of all months is equal to the quoted price. A derivative instrument that has a tenor that does not span the quoted period is considered an unobservable Level 3 measurement.

We evaluate and validate the inputs we use to estimate fair value by a number of methods, including validating against market published prices and daily broker quotes obtainable from multiple pricing services. For OTC derivative instruments classified as Level 2, indicative quotes obtained from brokers in liquid markets generally represent fair value of these instruments. We believe these price quotes are executable. Adjustments to the quotes are adjustments to the bid or ask price depending on the nature of the position to appropriately reflect exit pricing and are considered a Level 3 input to the fair value measurement. In less liquid markets such as coal, in which a single broker s view of the market is used to estimate fair value, we consider such inputs to be unobservable Level 3 inputs. We do not use third party sources that determine price based on market surveys or proprietary models.

We report our derivative assets and liabilities, for which the normal purchase/normal sale exception has not been made, at fair value and consider it to be a critical accounting estimate because these estimates are highly susceptible to change from period to period and are dependent on many subjective factors, including:

- estimated forward market price curves
- valuation adjustments relating to time value
- liquidity valuation adjustments
- credit adjustments, based on the credit standing of the counterparties and our own non-performance risk

Derivative assets are discounted for credit risk using a yield curve representative of the counterparty s probability of default. The counterparty s default probability is based on a modified version of published default rates, taking 20-year historical default rates from Standard & Poor s and Moody s and adjusting them to reflect a rolling five-year average. For derivative liabilities, fair value measurement reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying our credit default swap spread against the respective derivative liability.

To determine the fair value for Level 3 energy derivatives where there are no market quotes or external valuation services, we rely on various modeling techniques. We use a variety of valuation models, which vary in complexity depending on the contractual terms of, and inherent risks in, the instrument being valued. We use both industry-standard models as well as internally developed proprietary valuation models that consider various assumptions such as market prices for power and fuel, price shapes, ancillary services, volatilities and correlations as well as other relevant factors. There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

For additional information regarding our derivative assets and liabilities, see notes 2(d), 2(e) and 6 to our consolidated financial statements and Quantitative and Qualitative Disclosures about Market Risk in Item 7A of this Form 10-K.

Loss Contingencies.

We record loss contingencies when it is probable that a liability has been incurred and the amount can be reasonably estimated. We consider loss contingency estimates to be critical accounting estimates because they entail significant judgment regarding probabilities and ranges of exposure, and the ultimate outcome of the proceedings is unknown and could have a material adverse effect on our results of operations, financial condition and cash flows. See notes 16 and

17 to our consolidated financial statements.

Deferred Tax Assets, Valuation Allowances and Tax Liabilities.

We estimate (a) income taxes in the jurisdictions in which we operate, (b) deferred tax assets and liabilities based on expected future taxes in the jurisdictions in which we operate, (c) valuation allowances for deferred tax assets and (d) uncertain income tax positions. These estimates are considered critical accounting estimates because they require projecting future operating results (which is inherently imprecise) and judgments related to the ultimate determination of tax positions by taxing authorities. Also, these estimates depend on assumptions regarding our ability to generate future taxable income during the periods in which temporary differences are deductible. See note 14 to our consolidated financial statements for additional information.

We assess our future ability to use federal, state and foreign net operating loss carryforwards, capital loss carryforwards and other deferred tax assets using the more-likely-than-not criteria. These assessments include an evaluation of our recent history of earnings and losses, future reversals of temporary differences and identification of other sources of future taxable income, including the identification of tax planning strategies in certain situations.

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

Our primary market risk exposure relates to fluctuations in commodity prices, principally, natural gas, power, coal and oil. As described in notes 2(e) and 2(f) to our consolidated financial statements, we have a risk control framework to manage our risk exposure. However, the effectiveness of this framework can never be completely estimated or fully assured. For example, we could experience volatility in earnings from basis price differences, transmission issues, price correlation issues, volume variation or other factors, including margins being compressed as a result of market prices behaving differently than expected. In addition, a reduction in market liquidity may impair the effectiveness of our risk management practices and resulting hedge strategies. These and other factors could have a material adverse effect on our results of operations, financial condition and cash flows.

Non-Trading Market Risks

Commodity Price Risk

Changes in commodity prices prior to the energy delivery period are inherent in our business. Accordingly, we may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot market, (b) address operational requirements or (c) seek a specific financial objective. We use derivative instruments such as futures, forwards, swaps and options to execute our hedge strategy. For further discussion of these strategies and related market risks, see notes 2(e) and 6 to our consolidated financial statements.

As of December 31, 2009, the fair values of the contracts related to our net non-trading derivative assets and liabilities are (asset (liability)):

Sources of Fair Value	2010	2011	2012	2013	2014	2015 and Thereafter	Total Fair Value
				(in millions)			
Prices actively quoted (Level 1)	$ 23	$ 41	$	$	$	$	$ 64
Prices provided by other external sources (Level 2)	(39)	(36)	(13)				(88)
Prices based on models and other valuation methods (Level 3)	(23)						(23)
Total mark-to-market non-trading derivatives	$ (39)	$ 5	$ (13)	$	$	$	$ (47)

The fair values shown in the table above are subject to significant changes due to fluctuating commodity forward market prices, volatility and credit risk. Market prices assume a functioning market with an adequate number of buyers and sellers to provide liquidity. Insufficient market liquidity could significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged. For further discussion of how we arrive at these fair values, see note 2(d) to our consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations

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New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates Critical Accounting Estimates in Item 7 of this Form 10-K.

A hypothetical 10% movement in the underlying energy prices would have the following potential loss impacts on our non-trading derivatives:

As of December 31,	Market Prices	Earnings Impact	Fair Value Impact
		(in millions)	
2009	10% increase	$ (47)	$ (47)
2008	10% decrease	(5)	(5)

This risk analysis does not include the favorable impact that the same hypothetical price movements would have on our physical purchases and sales of fuel and power to which the hedges relate. The adverse impact of changes in commodity prices on our portfolio of non-trading energy derivatives would be offset (although not necessarily in the same period) by a favorable impact on the underlying physical transactions, assuming:

- the derivatives are not closed out in advance of their expected term
- the derivatives continue to function effectively as hedges of the underlying risk
- as applicable, anticipated underlying transactions settle as expected

If any of these assumptions cease to be true, we may experience a benefit or loss relative to the underlying exposure.

Interest Rate Risk

As of December 31, 2009 and 2008, we have no variable rate debt outstanding. We earn interest income, for which the interest rates vary, on our cash and cash equivalents and net margin deposits. Our variable rate interest expense and interest income was $0 and $2 million, respectively, during 2009 and $0 and $17 million, respectively, during 2008.

If interest rates decreased by one percentage point from their December 31, 2009 and 2008 levels, the fair values of our fixed rate debt would have increased by $126 million and $110 million, respectively.

Trading Market Risks

Prior to March 2003, we engaged in proprietary trading activities as discussed in note 5 to our consolidated financial statements. Trading positions entered into prior to our decision to exit this business are being closed on economical terms or are being retained and settled over the contract terms. In addition, we have transactions relating to non-core asset management, such as gas storage and transportation contracts not tied to generation assets, which are classified as trading activities.

As of December 31, 2009, the fair values of the contracts related to our legacy trading and non-core asset management positions and recorded as net derivative assets and liabilities are (asset (liability)):

2015 and	Total Fair

Sources of Fair Value	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Value**
				(in millions)			
Prices actively quoted (Level 1)	$ 24	$	$	$	$	$	$ 24
Prices provided by other external sources (Level 2)							
Prices based on models and other valuation methods (Level 3)	(5)						(5)
Total	$ 19	$	$	$	$	$	$ 19

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The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. See the discussion above related to non-trading derivative assets and liabilities for further information on items that impact our portfolio of trading contracts.

Our consolidated realized and unrealized margins relating to trading activities, including both derivative and non-derivative instruments, are (income (loss)):

	2009	2008
	(in millions)	
Realized	$ 31	$ 11
Unrealized	(11)	14
Total	$ 20	$ 25

An analysis of these net derivative assets and liabilities is:

	2009	2008
	(in millions)	
Fair value of contracts outstanding, beginning of period	$ 30	$ 19
Contracts realized or settled	(32)(1)	(9)(2)
Changes in fair values attributable to market price and other market changes	21	20
Fair value of contracts outstanding, end of period	$ 19	$ 30

(1) Amount includes realized gain of $31 million and deferred settlements of $1 million.

(2) Amount includes realized gain of $11 million partially offset by deferred settlements of $2 million.

We primarily assess the risk of our legacy trading and non-core asset management positions using a value-at-risk method to maintain our total exposure within limits set by the Audit Committee. Value-at-risk is the potential loss in value of trading positions due to adverse market movements over a defined time period within a specified confidence level. We use the parametric variance/covariance method with delta/gamma approximation to calculate value-at-risk.

Our value-at-risk model utilizes four major parameters:

Confidence level 95% for natural gas and petroleum products and 99% for power products

Volatility calculated daily from historical forward prices using the exponentially weighted moving average method

Correlation calculated daily from daily volatilities and historical forward prices using the exponentially weighted moving average method

Holding period natural gas and petroleum products generally have two day-holding periods. Power products have holding periods of five to 20 days based on the risk profile of the portfolio and the liquidation period

While we believe that our value-at-risk assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates. An inherent limitation of value-at-risk is that past market risk may not produce accurate predictions of future market risk. In addition, value-at-risk calculated for a specified holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within that specified period. Future transactions, market volatility, reduction of market liquidity, failure of counterparties to satisfy their contractual obligations and/or a failure of risk controls could result in material losses from our legacy trading and non-core asset management positions.

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The daily value-at-risk for our legacy trading and non-core asset management positions is:

	2009	2008
	(in millions)	
As of December 31	$ 1	$ 2
Year Ended December 31:		
Average	2	4
High	4	13
Low		

Item 8. ***Financial Statements and Supplementary Data.***

The information required by this Item is incorporated by reference from the consolidated financial statements beginning on page F-1.

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

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based on this evaluation, these officers have concluded that, as of the end of such period, our disclosure controls and procedures are effective.

Management s Annual Report on Internal Control Over Financial Reporting

The information required by this Item is incorporated by reference from RRI Energy, Inc. s Report on Internal Control Over Financial Reporting on page F-1.

Changes in Internal Control Over Financial Reporting

In connection with the evaluation described above, we identified no change in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during our fiscal quarter ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

See Business Executive Officers in Item 1 of this Form 10-K. Pursuant to General Instruction G to Form 10-K, we incorporate by reference the information to be disclosed in our definitive proxy statement for the annual stockholder meeting at which we will elect directors (Proxy Statement).

Item 11. *Executive Compensation.*

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our Proxy Statement.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Equity Compensation Plan Information

The following table provides information as of December 31, 2009 regarding our equity compensation plans.

	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights(1)	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in column (a))
Equity compensation plans approved by security holders(2)	6,487,502(3)	$ 14.09	23,247,230(4)
Equity compensation plans not approved by security holders(5)	717,806(6)	$ 8.42	3,618,389
Total	7,205,308	$ 13.67	26,865,619

(1) The weighted average exercise prices exclude shares issuable under outstanding time-based restricted stock units (which do not have an exercise price).

(2) Plans approved by stockholders include the RRI Energy, Inc. Employee Stock Purchase Plan, the 2002 Long-Term Incentive Plan, the Long-Term Incentive Plan of RRI Energy, Inc. and the RRI Energy, Inc. Transition Stock Plan.

(3) This amount includes 5,485,284 shares issuable upon the exercise of outstanding stock options and 1,002,218 shares issuable pursuant to outstanding restricted stock units granted under the 2002 Long-Term Incentive Plan.

(4) Includes stockholder approved reserves of 8,262,101 shares as of December 31, 2009 that may be issued under the Employee Stock Purchase Plan and 14,985,129 shares that may be issued under the 2002 Long-Term Incentive Plan. Under the 2002 Long-Term Incentive Plan, no more than 25% of the shares available for future issuance are available for grant as awards of restricted stock and non-restricted awards of common stock or units denominated in common stock. No additional shares may be issued under the Long-Term Incentive Plan of RRI Energy, Inc. or the RRI Energy, Inc. Transition Stock Plan. No additional shares may be issued under the RRI Energy, Inc. Employee Stock Purchase Plan as it was terminated effective December 31, 2009, other than the 431,733 shares issued in January 2010 for the last offering period.

(5) The RRI Energy Inc. 2002 Stock Plan permits grants of stock options, stock appreciation rights, performance based stock awards, time-based stock awards and cash awards to all employees other than the executive officers subject to the reporting requirements of Section 16(a) of the Exchange Act. The Board authorized 6,000,000 shares for grant upon adoption of the 2002 Stock Plan. To the extent these

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6,000,000 shares were not granted in 2002, the excess shares were cancelled. In January 2003, an additional 6,000,000 shares were authorized for the plan, with no more than 25% of these shares available for grant as awards of restricted stock and non-restricted awards of common stock or units denominated in common stock. The total number of shares available for future issuance is adjusted for new grants, exercises, forfeitures, cancellations and terminations of outstanding awards.

(6) This amount includes 436,579 shares issuable upon the exercise of outstanding stock options and 281,227 shares issuable pursuant to outstanding restricted stock units.

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our Proxy Statement under the captions Stock Ownership of Certain Beneficial Owners and Management Directors and Executive Officers, and Principal Stockholders.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Item 14. ***Principal Accountant Fees and Services.***

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into each of these Items 13 and 14 the information to be disclosed in our Proxy Statement.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) List of Documents Filed as Part of This Report.

(1) Index to Consolidated Financial Statements of RRI Energy, Inc. and Subsidiaries.

(2) Financial Statement Schedule.

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements.

The following financial statements are included in this report pursuant to Item 3-16 of Regulation S-X:

Consolidated Financial Statements of RRI Energy Mid-Atlantic Power Holdings, LLC and Subsidiaries

Consolidated Financial Statements of Orion Power Holdings, Inc. and Subsidiaries

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(3) Index to Exhibits.

The exhibits with the cross symbol (+) are filed with the Form 10-K. The exhibits with the asterisk symbol (*) are compensatory arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K. The representations, warranties and covenants contained in the exhibits were made only for purposes of such exhibits, as of specific dates, solely for the benefit of the parties thereto, may be subject to limitations agreed upon by those parties and may be subject to standards of materiality that differ from those applicable to investors. Investors should read such representations, warranties and covenants (or any descriptions thereof contained in the exhibits) in conjunction with information provided elsewhere in this filing and in our other filings and should not rely solely on such information as characterizations of our actual state of facts.

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
2.1	Asset Purchase Agreement by and among Reliant Energy Channelview LP, Reliant Energy Services Channelview LLC and GIM Channelview Cogeneration, LLC entered into June 9, 2008 and dated as of April 3, 2008 (This filing excludes schedules and exhibits, which the registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request)	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Quarterly Report on Form 10-Q for the period ended June 30, 2008	1-16455	2.1
2.2	Asset Purchase Agreement for Bighorn power plant by and among Reliant Energy Wholesale Generation, LLC, Reliant Energy Asset Management, LLC and Nevada Power Company dated as of April 21, 2008 (This filing excludes schedules and exhibits, which the registrant agrees to furnish supplementally to the Securities and Exchange Commission upon request)	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Quarterly Report on Form 10-Q for the period ended March 31, 2008	1-16455	2.1
2.3	Amendment No. 1 to Asset Purchase Agreement for Bighorn power plant by and among Reliant Energy Wholesale Generation, LLC, Reliant Energy Asset Management, LLC and Nevada Power Company, dated as of May 12, 2008	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Quarterly Report on Form 10-Q for the period ended June 30, 2008	1-16455	2.2
2.4			1-16455	2.4

LLC Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated as of February 28, 2009 (Portions of this Exhibit have been omitted pursuant to a request for confidential treatment)	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2008

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
2 .5	Letter Agreement dated March 24, 2009 re: Section 7.11 of the Membership Interest Purchase Agreement, dated as of February 28, 2009 by and between Reliant Energy, Inc. and NRG Retail LLC	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	2.1
2 .6	Letter Agreement dated April 9, 2009 re: Section 7.9(iv) of the Membership Interest Purchase Agreement, dated as of February 28, 2009 by and between Reliant Energy, Inc. and NRG Retail LLC	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	2.2
2 .7	Letter Agreement dated April 28, 2009 re: Sections 3.2(i), 7.12, 7.13(b) and 7.20 of the Membership Interest Purchase Agreement, dated as of February 28, 2009 by and between Reliant Energy, Inc. and NRG Retail LLC	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	2.3
2 .8	Letter Agreement dated April 30, 2009 re: Effectiveness of the Closing of the Membership Interest Purchase Agreement, dated as of February 28, 2009 by and between Reliant Energy, Inc. and NRG Retail LLC	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	2.4
3 .1	Third Restated Certificate of Incorporation	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	3.1
3 .2	Sixth Amended and Restated Bylaws	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	3.2
3 .3	Certificate of Ownership and Merger merging a wholly-owned subsidiary into registrant pursuant to Section 253 of the General Corporation Law of the State of Delaware, effective as of May 2, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	3.3
4 .1	Specimen Stock Certificate		333-48038	4.1

RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Amendment No. 5 to Registration Statement on Form S-1, filed March 23, 2001

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
4 .2	Rights Agreement between Reliant Resources, Inc. and The Chase Manhattan Bank, as Rights Agent, including a form of Rights Certificate, dated as of January 15, 2001	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	4.2
4 .3	Senior Indenture among Reliant Energy, Inc. and Wilmington Trust Company, dated as of December 22, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	4.1
4 .4	First Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of December 22, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	4.2
4 .5	Second Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of September 21, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	4.18
4 .6	Third Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	4.3
4 .7	Sixth Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among RRI Energy, Inc., The Guarantors listed therein and Wilmington Trust Company, dated as of June 1, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended September 30, 2009	1-16455	10.1
4 .8	Seventh Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among RRI Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of	RRI Energy s Current Report on Form 8-K, filed August 24, 2009	1-16455	99.1

	August 20, 2009
+4 .9	Eighth Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among RRI Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of December 1, 2009

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
4 .10	Indenture between Orion Power Holdings, Inc. and Wilmington Trust Company, dated as of April 27, 2000	Orion Power Holdings, Inc. s Registration Statement on Form S-1, filed August 18, 2000	333-44118	4.1
4 .11	Fourth Supplemental Indenture relating to the 7.625% Senior Notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of June 13, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed June 15, 2007	1-16455	4.1
4 .12	Fifth Supplemental Indenture relating to the 7.875% Senior Notes due 2017, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated as of June 13, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed June 15, 2007	1-16455	4.2
10 .1A	Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000	CenterPoint Energy Houston Electric, LLC s (formerly known as Reliant Energy, Incorporated) Quarterly Report on Form 10-Q for the period ended March 31, 2001	1-3187	10.1
+10 .1B	Schedules to Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000			
10 .2A	Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000	CenterPoint Energy Houston Electric, LLC s (formerly known as Reliant Energy, Incorporated) Quarterly Report on Form 10-Q for the period ended March 31, 2001	1-3187	10.8
+10 .2B	Exhibit to Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated as of December 31, 2000			
10 .3	Participating Preferred Stock Purchase Agreement by and between Reliant Energy, Inc. and FR Reliant Holdings LP dated as	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed October 16, 2008	1-16455	10.1

of October 10, 2008

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .4	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	10.2
10 .5A	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	10.3
+10 .5B	Exhibit C to Exhibit B to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004			
10 .6A	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	10.4

Energy, Inc., the Subsidiary
Guarantors defined therein and
J.P. Morgan Trust Company,
National Association, as trustee,
dated as of December 22, 2004

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10 .6B	Exhibit C to Exhibit B to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004			
10 .7A	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K filed December 27, 2004	1-16455	10.5
+10 .7B	Exhibit C to Exhibit B to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004			
10 .8A	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project),	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 27, 2004	1-16455	10.6

Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10 .8B	Exhibit C to Exhibit B to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated as of December 22, 2004			
10 .9	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated as of September 21, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	10.14
10 .10	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated as of September 21, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	10.15

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.11	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated as of September 21, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	10.16
10.12	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated as of September 21, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	10.17
10.13	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, as trustee, dated as of	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Annual Report on Form 10-K for the year ended December 31, 2006	1-16455	10.18

September 21, 2006

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .14	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	10.1
10 .15	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	10.2
10 .16	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	10.3

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.17	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	10.4
10.18	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of December 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed December 7, 2006	1-16455	10.5
10.19	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended September 30, 2009	1-16455	10.2
10.20	Third Supplemental Guarantee Agreement relating to	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the	1-16455	10.3

Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009	period ended September 30, 2009

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .21	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended September 30, 2009	1-16455	10.4
10 .22	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended September 30, 2009	1-16455	10.5
10 .23	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended September 30, 2009	1-16455	10.6
10 .24	Fourth Supplemental Guarantee Agreement relating to	RRI Energy, Inc. s Current Report on Form 8-K, filed August 24,	1-16455	99.2

Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of August 20, 2009	2009

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .25	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of August 20, 2009	RRI Energy, Inc. s Current Report on Form 8-K, filed August 24, 2009	1-16455	99.3
10 .26	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of August 20, 2009	RRI Energy, Inc. s Current Report on Form 8-K, filed August 24, 2009	1-16455	99.4
10 .27	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of August 20, 2009	RRI Energy, Inc. s Current Report on Form 8-K, filed August 24, 2009	1-16455	99.5

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .28	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of August 20, 2009	RRI Energy, Inc. s Current Report on Form 8-K, filed August 24, 2009	1-16455	99.6
+10 .29	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of December 1, 2009			
+10 .30	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of December 1,			

2009

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10 .31	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of December 1, 2009			
+10 .32	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of December 1, 2009			
+10 .33	Sixth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s exempt facilities revenues bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and the Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of December 1, 2009			

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .34A	Credit and Guaranty Agreement among Reliant Energy, Inc., as Borrower, the Other Loan Parties referred to therein as guarantors, the lenders party thereto, Deutsche Bank AG New York Branch, as Administrative Agent and Collateral Agent, Deutsche Bank Securities Inc. and J.P. Morgan Securities Inc., as Joint Lead Arrangers, Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and ABN AMRO Bank N.V., as Joint Bookrunners with respect to the Revolving Credit Facility and Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and Bear, Sterns & Co. Inc., as Joint Bookrunners with respect to the Pre-Funded L/C Facility, dated as of June 12, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc.) Current Report on Form 8-K, filed June 15, 2007	1-16455	1.1

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10 .34B	Exhibits and Schedules to Credit and Guaranty Agreement among Reliant Energy, Inc., as Borrower, the Other Loan Parties referred to therein as guarantors, the lenders party thereto, Deutsche Bank AG New York Branch, as Administrative Agent and Collateral Agent, Deutsche Bank Securities Inc. and J.P. Morgan Securities Inc., as Joint Lead Arrangers, Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and ABN AMRO Bank N.V., as Joint Bookrunners with respect to the Revolving Credit Facility and Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and Bear, Sterns & Co. Inc., as Joint Bookrunners with respect to the Pre-Funded L/C Facility, dated as of June 12, 2007 (Portions of this Exhibit have been omitted pursuant to a request for confidential treatment)			
10 .35	Facility Lease Agreement between Conemaugh Lessor Genco LLC and Reliant Energy Mid-Atlantic Power Holdings, LLC, dated as of August 24, 2000	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.6a
10 .36	Schedule identifying substantially identical agreements to Facility Lease Agreement constituting Exhibit 10.35	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.6b

10 .37	Pass Through Trust Agreement between Reliant Energy Mid-Atlantic Power Holdings, LLC and Bankers Trust Company, made with respect to the formation of the Series A Pass Through Trust and the issuance of 8.554% Series A Pass Through Certificates, dated as of August 24, 2000	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.4a

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .38	Schedule identifying substantially identical agreements to Pass Through Trust Agreement constituting Exhibit 10.37	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.4b
10 .39	Participation Agreement among (i) Conemaugh Lessor Genco LLC, as Owner Lessor; (ii) Reliant Energy Mid-Atlantic Power Holdings, LLC, as Facility Lessee; (iii) Wilmington Trust Company, as Lessor Manager; (iv) PSEGR Conemaugh Generation, LLC, as Owner Participant; (v) Bankers Trust Company, as Lease Indenture Trustee; and (vi) Bankers Trust Company, as Pass Through Trustee, dated as of August 24, 2000	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.5a
10 .40	Schedule identifying substantially identical agreements to Participation Agreement constituting Exhibit 10.39	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.5b
10 .41A	First Amendment to Participation Agreement, dated as of November 15, 2001	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005	1-16455	10.20
+10 .41B	Exhibit M to First Amendment to Participation Agreement, dated as of November 15, 2001			
10 .42	Schedule identifying substantially identical agreements to First Amendment to Participation Agreement constituting Exhibit 10.41A	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005	1-16455	10.21
10 .43	Second Amendment to Participation Agreement, dated as of June 18, 2003	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005	1-16455	10.22
10 .44			1-16455	10.23

Schedule identifying substantially identical agreements to Second Amendment to Participation Agreement constituting Exhibit 10.43	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .45	Lease Indenture of Trust, Mortgage and Security Agreement between Conemaugh Lessor Genco LLC, as Owner Lessor, and Bankers Trust Company, as Lease Indenture Trustee, dated as of August 24, 2000	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.8a
10 .46	Schedule identifying substantially identical agreements to Lease Indenture of Trust constituting Exhibit 10.45	RRI Energy Mid-Atlantic Power Holdings, LLC s (formerly Reliant Energy Mid-Atlantic Power Holdings, LLC s) Registration Statement on Form S-4, filed December 8, 2000	333-51464	4.8b
10 .47A	Purchase and Sale Agreement by and between Orion Power Holdings, Inc., Reliant Energy, Inc., Great Lakes Power Inc. and Brascan Corporation, dated as of May 18, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Current Report on Form 8-K, filed May 21, 2004	1-16455	99.2
+10 .47B	Schedules to Purchase and Sale Agreement by and between Orion Power Holdings, Inc., Reliant Energy, Inc., Great Lakes Power Inc. and Brascan Corporation, dated as of May 18, 2004			
10 .48A	Purchase and Sale Agreement between Orion Power Holdings, Inc., as Seller, Reliant Energy, Inc., as Guarantor, and Astoria Generating Company Acquisitions, L.L.C., as Buyer, dated as of September 30, 2005	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Current Report on Form 8-K, filed October 6, 2005	1-16455	10.1
+10 .48B	Exhibits and Schedules to Purchase and Sale Agreement between Orion Power Holdings, Inc., as Seller, Reliant Energy, Inc., as Guarantor, and Astoria Generating Company Acquisitions, L.L.C., as Buyer, dated as of September 30, 2005			
10 .49A	Settlement and Release of Claims Agreement among each	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Current	1-16455	10.1

of the Reliant Parties, OMOI, each of the California Parties, each of the Additional Claimants, each of the Class Action Parties and each of the Local Governmental Parties (each as defined therein), dated as of October 12, 2005	Report on Form 8-K, filed October 20, 2005

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10 .49B	Exhibits to Settlement and Release of Claims Agreement among each of the Reliant Parties, OMOI, each of the California Parties, each of the Additional Claimants, each of the Class Action Parties and each of the Local Governmental Parties (each as defined therein), dated as of October 12, 2005			
*10 .50	Executive Life Insurance Plan, effective as of January 1, 1994, including the first and second amendments thereto (RRI Energy, Inc. has adopted certain obligations under this plan with respect to Brian Landrum)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	10.30
*10 .51	Transition Stock Plan, effective as of May 4, 2001	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.37
*10 .52	2002 Stock Plan, effective as of March 1, 2002	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Registration Statement on Form S-8, filed April 19, 2002	333-86610	4.5
*10 .53	Annual Incentive Compensation Plan, effective as of January 1, 2001	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.9
*10 .54	First Amendment to Annual Incentive Compensation Plan, dated as of September 27, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.44
*10 .55	2002 Annual Incentive Compensation Plan for Executive Officers, effective as of March 1, 2002	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) 2002 Proxy Statement on Schedule 14A	1-16455	Appendix I
*10 .56	First Amendment to 2002 Annual Incentive Compensation Plan for Executive Officers, dated as of September 27, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.46

*10 .57	Long-Term Incentive Plan, effective as of January 1, 2001	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.10
*10 .58	2002 Long-Term Incentive Plan, effective as of June 6, 2002	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Registration Statement on Form S-8, filed April 19, 2002	333-86612	4.5
*10 .59	Deferral Plan, effective as of January 1, 2002	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Registration Statement on Form S-8, filed December 7, 2001	333-74790	4.1

Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10 .60	First Amendment to Deferral Plan, effective as of January 14, 2003	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2003	1-16455	10.5
*10 .61	Second Amendment to Deferral Plan, effective as of December 31, 2004	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.51
*10 .62	Deferral and Restoration Plan, effective as of January 1, 2005	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.52
*10 .63	Successor Deferral Plan, effective as of January 1, 2002	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.30
*10 .64	Deferred Compensation Plan, effective as of September 1, 1985, including the first nine amendments thereto (This is now a part of the plan listed as Exhibit 10.63)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	10.25
*10 .65	Deferred Compensation Plan, as amended and restated effective as of January 1, 1989, including the first nine amendments thereto (This is now a part of the plan listed as Exhibit 10.63)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	10.26
*10 .66	Deferred Compensation Plan, as amended and restated effective as of January 1, 1991, including the first ten amendments thereto (This is now a part of the plan listed as Exhibit 10.63)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	10.27
*10 .67	Benefit Restoration Plan, as amended and restated effective as of July 1, 1991, including the first amendment thereto (This is now a part of the plan listed as Exhibit 10.63)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Amendment No. 8 to Registration Statement on Form S-1, filed April 27, 2001	333-48038	10.12
*10 .68A	Key Employee Award Program 2004-2006 of the 2002 Long-Term Incentive Plan and the Form of Agreement for Key	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2004	1-16455	10.1

	Employee Award Program, effective as of February 13, 2004
+*10 .68B	Exhibit B to Key Employee Award Program 2004-2006 of the 2002 Long-Term Incentive Plan and the Form of Agreement for Key Employee Award Program, effective as of February 13, 2004

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10 .69	First Amendment to the Key Employee Award Program, effective as of August 10, 2005	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005	1-16455	10.44
*10 .70	Form of 2002 Stock Plan Nonqualified Stock Option Award Agreement, 2003 Grants	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.39
*10 .71	Form of Change in Control Agreement for CEO, CFO and COO	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.61
*10 .72	Form of Change in Control Agreement for certain officers other than CEO, CFO and COO	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.62
*10 .73	Reliant Energy, Inc. Executive Severance Plan, effective as of January 1, 2006	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2005	1-16455	10.57
*10 .74	First Amendment to Reliant Energy, Inc. Executive Severance Plan, dated as of September 27, 2007	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.64
*10 .75	Form of 2002 Long-Term Incentive Plan Nonqualified Stock Option Award Agreement for Directors	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.53
*10 .76	Form of 2002 Long-Term Incentive Plan Restricted Stock Award Agreement for Directors	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.54
*10 .77	Form of Amendment of 2002 Long-Term Incentive Plan Restricted Stock Award Agreement for Directors	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.67
*10 .78	Form of 2002 Long-Term Incentive Plan Quarterly Restricted and Premium Restricted Stock Units Award Agreement for Directors	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2004	1-16455	10.55
*10 .79	Form of 2002 Long-Term Incentive Plan Quarterly Common Stock and Premium	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year	1-16455	10.65

	Restricted Stock Award Agreement for Directors	ended December 31, 2007		
*10.80	Form of 2002 Long-Term Incentive Plan Restricted Stock Award Agreement for Directors	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2007	1-16455	10.66

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10 .81	Form of Long-Term Incentive Plan Restricted Stock Award Agreement for Directors initial grant	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Current Report on Form 8-K, filed August 24, 2006	1-16455	10.1
*10 .82	Reliant Energy, Inc. Non-Employee Directors Compensation Program, effective as of October 13, 2008	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.72
*10 .83	2002 Long-Term Incentive Plan 2008 Long-Term Incentive Award Program for officers (Form of Agreement included with Program)	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended March 31, 2008	1-16455	10.1
*10 .84	2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Program for Officers	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended March 30, 2007	1-16455	10.1
*10 .85	Form of 2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Agreement for Officers	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended March 30, 2007	1-16455	10.2
*10 .86	2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Agreement for Mark Jacobs	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	10.3
*10 .87	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff dated as of May 16, 2007 March 12, 2003 grant	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	10.4
*10 .88	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff dated as of May 16, 2007 May 8, 2003 grant	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	10.5
*10 .89	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff dated as of May 16, 2007 August 23, 2003	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	10.6

	grant			
*10 .90	2002 Long-Term Incentive Plan Amendment to Key Employee Award Program 2004-2006 Agreement by and between Reliant Energy, Inc. and Joel V. Staff dated as of May 16, 2007 February 13, 2004 grant	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	10.7

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10 .91	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Rick J. Dobson	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Quarterly Report on Form 10-Q for the period ended September 30, 2007	1-16455	10.2
*10 .92	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Albert H. Myres, Sr.	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2007	1-16455	10.77
*10 .93	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Charles Griffey	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2007	1-16455	10.78
*10 .94	2009 Long Term Incentive Award Program for Officers and Form of Award Agreement	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	10.1
*10 .95	2002 Long Term Incentive Plan Director Common Stock Award for Evan J. Silverstein	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	10.2
*10 .96	2002 Long Term Incentive Plan Form of Director Annual Award Agreement	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	10.3
*10 .97	2002 Long Term Incentive Plan Form of Quarterly Common Stock and Premium Restricted Stock Award for Directors	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	10.4
*10 .98	Non-Employee Directors Compensation Program, effective as of June 19, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	10.5
+*10 .99	Non-Employee Directors Compensation Program, effective as of January 1, 2010			
+*10 .100	2002 Long Term Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors			
*+10 .101	2002 Long Term Incentive Plan 2009 Long Term Incentive Award Program for officers (Form of 2009 Long Term Incentive Award Agreement Included with Program)			
10 .102	Guarantee by NRG Energy, Inc., as Guarantor, in favor of Reliant Energy, Inc. dated as of February 28, 2009	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.84

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Exhibit Number	Document Description	Reporter or Registration Statement	SEC File or Registration Number	Exhibit Reference
10 .103	Agreement Regarding Prosecution of Litigation by and among Merrill Lynch Commodities, Inc., Merrill Lynch & Co., Inc., Reliant Energy Power Supply, LLC, RERH Holdings, LLC, Reliant Energy Retail Holdings, LLC, Reliant Energy Retail Services, LLC, RE Retail Receivables, LLC and Reliant Energy Solutions East, LLC dated as of February 28, 2009	RRI Energy, Inc. s (formerly Reliant Energy, Inc. s) Annual Report on Form 10-K for the year ended December 31, 2008	1-16455	10.85
*+10 .104	Omnibus Amendment Reliant Energy, Inc. Executive Deferral, Incentive and Non-Qualified Plans effective as of May 2, 2009 (amending plans filed as Exhibits 10.51, 10.52, 10.53, 10.55, 10.57, 10.58, 10.59, 10.62 and 10.63)			
*+10 .105	Omnibus Amendment Reliant Energy, Inc. Severance Plans effective as of May 2, 2009 (amending Reliant Energy, Inc. Executive Severance Plan filed as Exhibit 10.73)			
+12 .1	RRI Energy, Inc. and Subsidiaries Ratio of Earnings from Continuing Operations to Fixed Charges			
+21 .1	Subsidiaries of RRI Energy, Inc.			
+23 .1	Consent of KPMG LLP, independent registered public accounting firm of RRI Energy, Inc.			
+31 .1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
+31 .2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			

+32 .1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)
+101	Interactive Data File

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

RRI Energy, Inc.
(Registrant)

By:
/s/ Mark M. Jacobs

Mark M. Jacobs
President and Chief Executive Officer

February 25, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 25, 2010.

Signature	Title
/s/ Mark M. Jacobs	**President and Chief Executive Officer**
Mark M. Jacobs	
/s/ Rick J. Dobson	**Executive Vice President and Chief Financial Officer (Principal Financial Officer)**
Rick J. Dobson	
/s/ Thomas C. Livengood	**Senior Vice President and Controller (Principal Accounting Officer)**
Thomas C. Livengood	
/s/ E. William Barnett	**Director**
E. William Barnett	
/s/ Mark M. Jacobs	**Director**
Mark M. Jacobs	
/s/ Steven L. Miller	**Director**
Steven L. Miller	
/s/ Laree E. Perez	**Director**

Laree E. Perez	
/s/ Evan J. Silverstein	**Director**
Evan J. Silverstein	

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RRI ENERGY, INC. S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of RRI Energy, Inc. and its subsidiaries (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, our management used the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment we believe that, as of December 31, 2009, our internal control over financial reporting is effective based on those criteria.

Our independent auditors have issued an audit report on our internal control over financial reporting. This report appears on page F-2.

/s/ Mark M. Jacobs	*/s/ Rick J. Dobson*
Mark M. Jacobs President and Chief Executive Officer	Rick J. Dobson Executive Vice President and Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
RRI Energy, Inc.:

We have audited the accompanying consolidated balance sheets of RRI Energy, Inc. and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we have also audited financial statement schedule II Valuation and Qualifying Accounts for each of the years in the three-year period ended December 31, 2009. We have also audited the Company s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for these consolidated financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Internal Control Over Financial Reporting on page F-1. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of RRI Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also in our opinion, RRI Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in notes 2(d) and 23(c) to the consolidated financial statements, the Company changed its method of accounting for fair value measurements of financial instruments due to the adoption of new accounting requirements issued by the FASB, as of January 1, 2008.

KPMG LLP

Houston, Texas
February 24, 2010

RRI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	2009	2008	2007
	(thousands of dollars, except per share amounts)		
Revenues:			
Revenues (including $(44,170), $(1,151) and $31,662 unrealized gains (losses)) (including $0, $253,001 and $127,083 from affiliates)	$ 1,824,839	$ 3,393,900	$ 3,202,528
Expenses:			
Cost of sales (including $65,961, $(7,405) and $(25,113) unrealized gains (losses)) (including $0, $71,568 and $42,645 from affiliates)	1,129,249	1,913,689	2,040,769
Operation and maintenance	550,253	595,262	642,406
General and administrative	100,745	121,173	134,488
Western states litigation and similar settlements		37,467	22,000
Gains on sales of assets and emission and exchange allowances, net	(21,913)	(92,202)	(25,699)
Goodwill and long-lived assets impairments	210,771	304,859	
Depreciation and amortization	269,191	312,642	398,691
Total operating expense	2,238,296	3,192,890	3,212,655
Operating Income (Loss)	(413,457)	201,010	(10,127)
Other Income (Expense):			
Income of equity investment, net	605	1,198	4,686
Debt extinguishments losses	(7,501)	(2,257)	(113,522)
Other, net	(248)	4,727	4
Interest expense	(186,296)	(199,590)	(262,410)
Interest income	2,516	21,178	19,638
Total other expense	(190,924)	(174,744)	(351,604)
Income (Loss) from Continuing Operations Before Income Taxes	(604,381)	26,266	(361,731)
Income tax expense (benefit)	(125,349)	136,532	(160,100)
Loss from Continuing Operations	(479,032)	(110,266)	(201,631)
Income (loss) from discontinued operations	881,844	(629,409)	566,738
Net Income (Loss)	$ 402,812	$ (739,675)	$ 365,107

Basic Earnings (Loss) per Share:						
Loss from continuing operations	$	(1.36)	$	(0.32)	$	(0.59)
Income (loss) from discontinued operations		2.51		(1.81)		1.66
Net income (loss)	$	1.15	$	(2.13)	$	1.07
Diluted Earnings (Loss) per Share:						
Loss from continuing operations	$	(1.36)	$	(0.32)	$	(0.59)
Income (loss) from discontinued operations		2.51		(1.81)		1.66
Net income (loss)	$	1.15	$	(2.13)	$	1.07

See Notes to our Consolidated Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(thousands of dollars, except per share amounts)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 943,440	$ 1,004,367
Restricted cash	24,093	2,721
Accounts and notes receivable, principally customer, net	152,569	249,871
Inventory	331,584	314,999
Derivative assets	132,062	161,340
Margin deposits	198,582	32,676
Investment in and receivables from Channelview, net		58,703
Prepayments and other current assets	86,844	124,449
Current assets of discontinued operations ($55,855 and $295,477 of margin deposits)	108,476	2,506,340
Total current assets	1,977,650	4,455,466
Property, Plant and Equipment, net	4,602,313	4,819,789
Other Assets:		
Other intangibles, net	305,913	380,554
Derivative assets	53,138	78,879
Prepaid lease	277,370	273,374
Other ($33,793 and $29,012 accounted for at fair value)	239,078	219,552
Long-term assets of discontinued operations	5,232	494,781
Total other assets	880,731	1,447,140
Total Assets	$ 7,460,694	$ 10,722,395
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 404,505	$ 12,517
Accounts payable, principally trade	142,787	156,604
Derivative liabilities	151,461	202,206
Margin deposits	2,860	93,000
Other	169,898	199,026
Current liabilities of discontinued operations ($11,000 and $0 of margin deposits)	58,452	2,375,895
Total current liabilities	929,963	3,039,248

Other Liabilities:		
Derivative liabilities	61,436	140,493
Other	260,547	272,079
Long-term liabilities of discontinued operations	13,700	873,190
Total other liabilities	335,683	1,285,762
Long-term Debt	1,949,771	2,610,737
Commitments and Contingencies		
Temporary Equity Stock-based Compensation	6,890	9,004
Stockholders Equity:		
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)		
Common stock; par value $0.001 per share (2,000,000,000 shares authorized; 352,785,985 and 349,812,537 issued)	114	111
Additional paid-in capital	6,259,248	6,238,639
Accumulated deficit	(1,972,389)	(2,375,201)
Accumulated other comprehensive loss	(48,586)	(85,905)
Total stockholders equity	4,238,387	3,777,644
Total Liabilities and Equity	$ 7,460,694	$ 10,722,395

See Notes to our Consolidated Financial Statements

RRI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2009	2008	2007
	(thousands of dollars)		
Cash Flows from Operating Activities:			
Net income (loss)	$ 402,812	$ (739,675)	$ 365,107
(Income) loss from discontinued operations	(881,844)	629,409	(566,738)
Loss from continuing operations	(479,032)	(110,266)	(201,631)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Goodwill and long-lived assets impairments	210,771	304,859	
Depreciation and amortization	269,191	312,642	398,691
Deferred income taxes	(120,646)	99,930	(153,344)
Net changes in energy derivatives	(21,285)	8,556	(6,549)
Amortization of deferred financing costs	7,086	6,653	9,213
Debt extinguishments losses	7,501	2,257	113,522
Gains on sales of assets and emission and exchange allowances, net	(21,913)	(92,202)	(25,699)
Western states litigation and similar settlements		3,467	
Other, net	(13,121)	(10,486)	6,342
Changes in other assets and liabilities:			
Accounts and notes receivable, net	108,985	9,978	(40,630)
Changes in notes, receivables and payables with affiliate, net	43	3,687	(13,078)
Inventory	(14,711)	(31,862)	(21,863)
Margin deposits, net	(256,046)	199,370	285,641
Net derivative assets and liabilities	(32,460)	3,049	(8,253)
Western states litigation and similar settlements payments	(3,449)		(35,000)
Accounts payable	(12,776)	(48,470)	(19,771)
Other current assets	12,269	1,969	2,559
Other assets	(6,466)	10,207	(12,633)
Taxes payable/receivable	(6,883)	24,325	(9,166)
Other current liabilities	(11,157)	10,091	(56,011)
Other liabilities	(7,417)	(4,327)	(8,810)
Net cash provided by (used in) continuing operations from operating activities	(391,516)	703,427	203,530
Net cash provided by (used in) discontinued operations from operating activities	585,045	(520,732)	558,213
Net cash provided by operating activities	193,529	182,695	761,743
Cash Flows from Investing Activities:			
Capital expenditures	(189,511)	(278,757)	(174,589)
Proceeds from sales of assets, net	35,931	526,956	82,075
Proceeds from sales of emission and exchange allowances	19,180	42,458	6,815

Purchases of emission allowances	(22,711)	(60,986)	(91,923)
Restricted cash	(4,620)	530	(6,326)
Other, net	3,750	6,562	6,045
Net cash provided by (used in) continuing operations from investing activities	(157,981)	236,763	(177,903)
Net cash provided by (used in) discontinued operations from investing activities	311,800	(20,128)	(747)
Net cash provided by (used in) investing activities	153,819	216,635	(178,650)
Cash Flows from Financing Activities:			
Proceeds from long-term debt			1,300,000
Payments of long-term debt	(254,980)	(57,704)	(1,535,887)
Increase in short-term borrowings and revolving credit facilities, net			6,554
Payments of financing costs			(31,245)
Payments of debt extinguishments expenses	(4,778)	(1,017)	(72,779)
Proceeds from issuances of stock	11,245	13,570	41,317
Net cash used in continuing operations from financing activities	(248,513)	(45,151)	(292,040)
Net cash used in discontinued operations from financing activities	(260,707)		
Net cash used in financing activities	(509,220)	(45,151)	(292,040)
Net Change in Cash and Cash Equivalents, Total Operations	(161,872)	354,179	291,053
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations	(100,945)	(126,118)	92,066
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	1,004,367	524,070	325,083
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 943,440	$ 1,004,367	$ 524,070
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest paid (net of amounts capitalized) for continuing operations	$ 194,355	$ 205,956	$ 299,379
Income taxes paid (net of income tax refunds received) for continuing operations	2,330	12,312	2,833

See Notes to our Consolidated Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)

				Accumulated Other Comprehensive Income (Loss)						
	Common Stock	Additional Paid In Capital	Accumulated Deficit	Unrealized Gain (Loss) on Available-For-Sale Securities	Deferred Derivative Gains (Losses)	Benefits Actuarial Net Gain (Loss)	Benefits Net Prior Service Costs	Total Accumulated Other Comprehensive Income (Loss)	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Tot Stockh Equ
			(thousands of dollars)							
,	$ 99	$ 6,174,665	$ (2,026,316)	$	$ (178,402)	$ (15,463)	$ (10,869)	$ (204,734)	$ 6,159	$ 3,94
		(468)	25,683							2
	99	6,174,197	(2,000,633)		(178,402)	(15,463)	(10,869)	(204,734)	6,159	3,97
			365,107							36
		(2,487)								(
	1	43								
	6	43,659								4
		100								
sh										
					3,225			3,225		
n										
					93,933			93,933	(5,030)	8
							1,308	1,308		

0										
et										
						356		356		
of										
						1,725		1,725		
e										
,	$ 106	$ 6,215,512	$ (1,635,526)	$	$ (81,244)	$ (13,382)	$ (9,561)	$ (104,187)	$ 1,129	$ 4,47
			(739,675)							(73
	5	2,070								
		19,039								1
		2,018								
n										
					32,605			32,605	(1,129)	3
							961	961		
f										
						188		188		
of										
						(20,111)	(810)	(20,921)		(2
f										
				5,449				5,449		
,	$ 111	$ 6,238,639	$ (2,375,201)	$ 5,449	$ (48,639)	$ (33,305)	$ (9,410)	$ (85,905)	$	$ 3,77

			402,812							40
	3	20,609								2
n										
					14,791			14,791		1
0							6,046	6,046		
et						2,977		2,977		
of on						10,091	351	10,442		1
f				3,063				3,063		
e										
-,	$ 114	$ 6,259,248	$ (1,972,389)	$ 8,512	$ (33,848)	$ (20,237)	$ (3,013)	$ (48,586)	$	$ 4,23

See Notes to our Consolidated Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

Background. RRI Energy refers to RRI Energy, Inc. and we, us and our refer to RRI Energy, Inc. and its consolida subsidiaries. We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through our ownership and operation of and contracting for power generation capacity. Our business consists of four reportable segments. See note 20.

RRI Energy, a Delaware corporation, was formed in August 2000 by CenterPoint Energy, Inc. (CenterPoint) (known as Reliant Energy, Incorporated at the time) in connection with the planned separation of its regulated and unregulated operations. CenterPoint transferred substantially all of its unregulated businesses to us. In May 2001, Reliant Energy became a publicly traded company and in September 2002, CenterPoint distributed its remaining ownership of our common stock to its shareholders.

We sold our retail business in three transactions occurring in December 2008, May 2009 and December 2009. We began reporting this business as discontinued operations in the first quarter of 2009. In connection with the Texas retail sale, we changed our name to RRI Energy, Inc. from Reliant Energy, Inc. effective May 2, 2009. See note 23.

Basis of Presentation. All significant intercompany transactions have been eliminated.

Channelview. In August 2007, four of our wholly-owned subsidiaries, Reliant Energy Channelview LP (Channelview LP), Reliant Energy Channelview (Texas) LLC, Reliant Energy Channelview (Delaware) LLC and Reliant Energy Services Channelview LLC (collectively, Channelview), filed for reorganization under Chapter 11 of the Bankruptcy Code. As Channelview was subject to the supervision of the bankruptcy court, we deconsolidated Channelview s financial results beginning August 20, 2007, and began reporting our investment in Channelview using the cost method. The Channelview plant was sold in July 2008. Channelview emerged from bankruptcy in October 2009 at which time we reconsolidated the entities. See note 22.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates and Market Risk and Uncertainties.

Management makes estimates and assumptions to prepare financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) that affect:

- the reported amounts of assets, liabilities and equity
- the reported amounts of revenues and expenses
- our disclosure of contingent assets and liabilities at the date of the financial statements

Actual results could differ from those estimates.

We evaluate our estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which we believe to be reasonable under the circumstances. We adjust such estimates and assumptions when facts and circumstances dictate. We have evaluated subsequent events for recording and disclosure to February 25, 2010, the date the financial statements were issued.

Our critical accounting estimates include: (a) fair value of derivative assets and liabilities; (b) recoverability and fair value of long-lived assets; (c) loss contingencies and (d) deferred tax assets, valuation allowances and tax liabilities.

We are subject to various risks inherent in doing business. See notes 2(c), 2(d), 2(e), 2(f), 2(g), 2(l), 2(m), 2(n), 2(o), 2(p), 3, 4, 5, 6, 7, 10, 11, 12, 13, 14, 15, 16, 17, 21, 22 and 23.

(b) Principles of Consolidation.

We include our accounts and those of our wholly-owned subsidiaries in our consolidated financial statements, excluding Channelview during its deconsolidation from August 2007 through October 2009. We do not consolidate three power generating facilities (see note 15(a)), which are under operating leases, or a 50% equity investment in a cogeneration plant.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Revenues.

Power Generation Revenues. We record gross revenues from the sales of power and other energy services under the accrual method. Electric power and other energy services are sold at market-based prices through existing power exchanges or third party contracts. Energy sales and services that have been delivered but not billed by period end are estimated. During 2009, 2008 and 2007, we recorded $922 million, $2.1 billion and $2.1 billion, respectively, in power generation revenues.

Capacity Revenues. We record gross revenues from the sales of capacity under the accrual method. These sales are sold at market-based prices primarily through the RPM auction market in PJM. We also sell in MISO, Cal ISO and other markets where we enter into agreements with counterparties. Sales that have been delivered but not billed by period end are estimated. During 2009, 2008 and 2007, we recorded $536 million, $455 million and $268 million, respectively, in capacity revenues.

Natural Gas Sales Revenues. We record gross revenues from the sales of natural gas under the accrual method. These sales are sold at market-based prices through third party contracts or related party affiliates. Sales that have been delivered but not billed by period end are estimated. During 2009, 2008 and 2007, we recorded $381 million, $948 million and $994 million, respectively, in natural gas sales revenues.

(d) Fair Value Measurements.

Fair Value Hierarchy and Valuation Techniques. We apply recurring fair value measurements to our financial assets and liabilities. In determining fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. These inputs can be readily observable, market corroborated, or generally unobservable internally developed inputs. Based on the observability of the inputs used in our valuation techniques, our financial assets and liabilities are classified as follows:

Level 1: 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 our energy derivative instruments that are exchange-traded or that are cleared and settled through the exchange. Our cash equivalents and available-for-sale and trading securities are also valued using Level 1 inputs.

Level 2: 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 includes emission allowances futures that are exchange-traded and over-the-counter (OTC) derivative instruments such as generic swaps, forwards and options.

Level 3: This category includes our energy derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from objective sources (such as implied volatilities and correlations). Our 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, longer term natural gas contracts and options valued using implied or internally developed inputs.

We value some of our OTC, complex or structured derivative instruments using valuation models, which utilize inputs that may not be corroborated by market data, such as market prices for power and fuel, price shapes, volatilities and correlations as well as other relevant factors. When such inputs are significant to the fair value measurement, the derivative assets or liabilities are classified as Level 3 when we do not have corroborating market evidence to support significant valuation model inputs and cannot verify the model to market transactions. We believe the transaction price is the best estimate of fair value at inception under the exit price methodology.

Accordingly, when a pricing model is used to value such an instrument, the resulting value is adjusted so the model value at inception equals the transaction price. Valuation models are typically impacted by Level 1 or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Subsequent to initial recognition, we update Level 1 and Level 2 inputs to reflect observable market changes. Level 3 inputs

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are updated when corroborated by available market evidence. In the absence of such evidence, management s best estimate is used.

See note 4 for discussion of our fair value measurements for some non-financial assets.

Fair Value of Derivative Instruments and Certain Other Assets. We apply recurring fair value measurements to our financial assets and liabilities. Fair value measurements of our financial assets and liabilities are as follows:

	December 31, 2009				
	Level 1	Level 2	Level 3	Reclassifications[1]	Total Fair Value
	(in millions)				
Total derivative assets	$ 137	$ 46	$ 4	$ (2)	$ 185
Total derivative liabilities	49	134	32	(2)	213
Cash equivalents[2]	965				965
Other assets[3]	34				34

(1) Reclassifications are required to reconcile to our consolidated balance sheet presentation.

(2) Represent investments in money market funds and are included in cash and cash equivalents and restricted cash in our consolidated balance sheet. We had $943 million of cash equivalents included in cash and cash equivalents and $22 million of cash equivalents included in restricted cash.

(3) Include $13 million in available-for-sale securities (shares in a public exchange) and $21 million in trading securities (rabbi trust investments (which are comprised of mutual funds) associated with our non-qualified deferred compensation plans for key and highly compensated employees).

	December 31, 2008				
	Level 1	Level 2	Level 3	Reclassifications[1]	Total Fair Value
	(in millions)				
Total derivative assets	$ 125	$ 111	$ 7	$ (3)	$ 240
Total derivative liabilities	17	208	121	(3)	343
Cash equivalents[2]	1,004				1,004
Other assets[3]	29				29

(1) Reclassifications are required to reconcile to our consolidated balance sheet presentation.

(2) Represent investments in money market funds and are included in cash and cash equivalents in our consolidated balance sheet. We had $1.0 billion of cash equivalents included in cash and cash equivalents.

(3) Include $8 million in available-for-sale securities (shares in a public exchange) and $21 million in trading securities (rabbi trust investments (which is comprised of mutual funds) associated with our non-qualified deferred compensation plans for key and highly compensated employees).

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The following is a reconciliation of changes in fair value of net derivative assets and liabilities classified as Level 3:

	Net Derivatives (Level 3) 2009	2008
	(in millions)	
Balance, beginning of period (net asset (liability))	$ (114)	$ 21
Total gains (losses) realized/unrealized:		
Included in earnings[1]	(79)	127
Purchases, issuances and settlements (net)	165	(262)
Transfers in and/or out of Level 3 (net)		
Balance, end of period (net asset (liability))	$ (28)	$ (114)
Changes in unrealized gains (losses) relating to derivative assets and liabilities still held as of December 31, 2009 and 2008:		
Revenues	$ (1)	$
Cost of sales	(23)	5
Total	$ (24)	$ 5

(1) Recorded in revenues and cost of sales.

Nonperformance Risk on Derivative Liabilities. Fair value measurement of our derivative liabilities reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying our credit default swap spread against the respective derivative liability. As of December 31, 2009 and 2008, we had $1 million and $15 million, respectively, in reserves for nonperformance risk on derivative liabilities. This change in accounting estimate had an impact during 2008 as follows (income (loss)):

	2008 Loss from Continuing Operations before Income Taxes	Net Loss
	(in millions)	
Total derivative liabilities	$ 15(1)	$ 10(2)

(1) This amount represented a decrease in our net derivative liabilities with the corresponding unrealized gains of $7 million and $8 million recorded in revenues and cost of sales, respectively.

(2) This represents an $0.03 impact on loss per share for 2008.

Fair Value of Other Financial Instruments. The fair values of cash, accounts receivable and payable and margin deposits approximate their carrying amounts. Values of our debt for continuing operations (see note 6) are:

	December 31, 2009		December 31, 2008	
	Carrying Value	**Fair Value(1)**	**Carrying Value**	**Fair Value(1)**
	(in millions)			
Fixed rate debt	$ 2,355	$ 2,333	$ 2,623	$ 2,168
Total debt	$ 2,355	$ 2,333	$ 2,623	$ 2,168

(1) We based the fair values of our fixed rate debt on market prices and quotes from an investment bank.

See notes 2(e) and 6.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(e) Derivatives and Hedging Activities.

Changes in commodity prices prior to the energy delivery period are inherent in our business. Accordingly, we may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. For our risk management activities, we use derivative and non-derivative contracts that provide for settlement in cash or by delivery of a commodity. We use derivative instruments such as futures, forwards, swaps and options to execute our hedge strategy. We may also enter into derivatives to manage our exposure to changes in prices of emission and exchange allowances.

We account for our derivatives under one of three accounting methods (mark-to-market, accrual (under the normal purchase/normal sale exception to fair value accounting) or cash flow hedge accounting) based on facts and circumstances. See note 2(d) for discussion on fair value measurements.

A derivative is recognized at fair value in the balance sheet whether or not it is designated as an accounting hedge, except for derivative contracts designated as normal purchase/normal sale exceptions, which are not in our consolidated balance sheet or results of operations prior to settlement resulting in accrual accounting treatment.

Realized gains and losses on derivative contracts used for risk management purposes and not held for trading purposes are reported either on a net or gross basis based on the relevant facts and circumstances. Hedging transactions that do not physically flow are included in the same caption as the items being hedged.

A summary of our derivative activities and classification in our results of operations is:

Instrument	Primary Risk Exposure	Purpose for Holding or Issuing Instrument[1]	Transactions that Physically Flow/Settle[2]	Transactions that Financially Settle[3]
Power futures, forward, swap and option contracts	Price risk	Power sales to customers	Revenues	Revenues
		Power purchases related to operations	Cost of sales	Revenues
		Power purchases/sales related to legacy trading and non-core asset management positions[4]	Revenues	Revenues
Natural gas and fuel futures, forward, swap and option contracts	Price risk	Natural gas and fuel sales related to operations	Revenues/ Cost of sales	Cost of sales
		Natural gas sales related to power generation[5]	N/A[6]	Revenues

		Natural gas and fuel purchases related to operations	Cost of sales	Cost of sales
		Natural gas and fuel purchases/sales related to legacy trading and non-core asset management positions(4)	Cost of sales	Cost of sales
Emission and exchange allowances futures(7)	Price risk	Purchases/sales of emission and exchange allowances	N/A(6)	Revenues/ Cost of sales

(1) The purpose for holding or issuing does not impact the accounting method elected for each instrument.

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(2) Includes classification of unrealized gains and losses for derivative transactions reclassified to inventory or intangibles upon settlement.

(3) Includes classification for mark-to-market derivatives and amounts reclassified from accumulated other comprehensive income (loss) related to cash flow hedges.

(4) See discussion below regarding trading activities.

(5) Natural gas financial swaps and options transacted to economically hedge generation in the PJM region.

(6) N/A is not applicable.

(7) Includes emission and exchange allowances futures for sulfur dioxide (SO_2), nitrogen oxide (NO_X) and carbon dioxide (CO_2).

In addition to price risk, we are exposed to credit and operational risk. We have a risk control framework to manage these risks, which include: (a) measuring and monitoring these risks, (b) review and approval of new transactions relative to these risks, (c) transaction validation and (d) portfolio valuation and reporting. We use mark-to-market valuation, value-at-risk and other metrics in monitoring and measuring risk. Our risk control framework includes a variety of separate but complementary processes, which involve commercial and senior management and our Board of Directors. See note 2(f) for further discussion of our credit policy.

Earnings Volatility from Derivative Instruments. We procure power, natural gas, coal, oil, natural gas transportation and storage capacity and other energy-related commodities to support our business. We may experience volatility in our earnings resulting from contracts receiving accrual accounting treatment while related derivative instruments are marked to market through earnings. As discussed in note 2(a), our financial statements include estimates and assumptions made by management throughout the reporting periods and as of the balance sheet dates. It is reasonable that subsequent to the balance sheet date of December 31, 2009, changes, some of which could be significant, have occurred in the inputs to our various fair value measures, particularly relating to commodity price movements.

Unrealized gains and losses on energy derivatives consist of both gains and losses on energy derivatives during the current reporting period for derivative assets or liabilities that have not settled as of the balance sheet date and the reversal of unrealized gains and losses from prior periods for derivative assets or liabilities that settled prior to the balance sheet date during the current reporting period.

Cash Flow Hedges. During the first quarter of 2007, we de-designated our remaining cash flow hedges; therefore, as of December 31, 2009 and 2008, we do not have any designated cash flow hedges. The fair value of our de-designated cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts have been effective as hedges, until the forecasted transactions affect earnings. At the time the forecasted transactions affect earnings, we reclassify the amounts in accumulated other comprehensive loss into earnings.

Presentation of Derivative Assets and Liabilities. We present our derivative 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.

(f) Credit Risk.

We have a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. Credit risk is monitored daily and the financial condition of our counterparties is reviewed periodically. We try to mitigate credit risk by entering into contracts that permit netting and allow us to terminate upon the occurrence of certain events of default. We measure credit risk as the replacement cost for our derivative positions plus amounts owed for settled transactions.

Our credit exposure is based on our derivative assets and accounts receivable from our counterparties, after taking into consideration netting within each contract and any master netting contracts with counterparties. We believe this represents the maximum potential loss we could incur if our counterparties failed to perform according to their contract terms.

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As of December 31, 2009, our derivative assets and accounts receivable, after taking into consideration netting within each contract and any master netting contracts with counterparties, are:

Credit Rating Equivalent		Exposure Before Collateral(1)(2)	Credit Collateral Held(3)	Exposure Net of Collateral	Number of Counterparties >10%	Net Exposure of Counterparties >10%
				(dollars in millions)		
Investment grade		$ 126	$ 12	$ 114	3(4)	$ 91
Non-investment grade		3	3			
No external ratings:						
Internally rated	Investment grade	48		48	1(5)	42
Internally rated	Non-investment grade	17	16	1		
Total		$ 194	$ 31	$ 163	4	$ 133

(1) The table includes amounts related to certain contracts classified as discontinued operations in our consolidated balance sheets. These contracts settle through the expiration date in 2013.

(2) The table excludes amounts related to contracts classified as normal purchase/normal sale and non-derivative contractual commitments that are not recorded in our consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Nonperformance could have a material adverse impact on our future results of operations, financial condition and cash flows.

(3) Collateral consists of cash, standby letters of credit and other forms approved by management.

(4) These counterparties are two power grid operators and one financial institution.

(5) This counterparty is a financial institution.

As of December 31, 2008, three investment grade counterparties (a financial institution and two power grid operators) represented 63% ($156 million) of our credit exposure.

Based on our current credit ratings, any additional collateral postings that would be required from us due to a credit downgrade would be immaterial. As of December 31, 2009 and December 31, 2008, we have posted cash margin deposits of $117 million and $70 million, respectively, as collateral for our derivative liabilities receiving mark-to-market accounting treatment and our accounts payable (classified either as continuing or discontinued operations). Additionally, as of December 31, 2009 and 2008, we have $5 million and $103 million, respectively, in letters of credit issued as collateral for our derivative liabilities receiving mark-to-market accounting treatment and our accounts payable (classified either as continuing or discontinued operations). See note 7.

(g) Property, Plant and Equipment and Depreciation Expense.

We compute depreciation using the straight-line method based on estimated useful lives. Depreciation expense was $241 million, $241 million and $283 million during 2009, 2008 and 2007, respectively.

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	Estimated Useful Lives (Years)	December 31, 2009	December 31, 2008
		(in millions)	
Electric generation facilities	5 - 35	$ 5,378(1)	$ 5,481(2)
Building and building improvements	5 - 15	13	27
Land improvements	20 - 35	191	206
Other	3 - 10	254	241
Land		109	82
Assets under construction		386	381
Total		6,331	6,418
Accumulated depreciation		(1,729)	(1,598)
Property, plant and equipment, net		$ 4,602	$ 4,820

(1) Includes $234 million ($212 million net of accumulated depreciation) relating to leasehold improvements for the Keystone, Shawville and Conemaugh plants. The original depreciation periods for these leasehold improvements range from primarily 10 to 31 years.

(2) Includes $169 million ($152 million net of accumulated depreciation) relating to leasehold improvements for the Keystone, Shawville and Conemaugh plants.

See note 4 for discussion of our recoverability assessments of long-lived assets (property, plant and equipment and related intangible assets) and the impairments recognized during 2009 for our New Castle and Indian River plants.

(h) Intangible Assets and Amortization Expense.

Goodwill. We performed our goodwill impairment test annually on April 1 and when events or changes in circumstances indicated that the carrying value may not have been recoverable. During 2008, we impaired our remaining goodwill of continuing operations. See note 5.

Other Intangibles. We recognize specifically identifiable intangible assets, including emission allowances, power generation site permits and water rights, when specific rights and contracts are acquired. We have no intangible assets with indefinite lives recorded as of December 31, 2009 and 2008. See note 4 for discussion of our recoverability assessments of long-lived assets (property, plant and equipment and related intangible assets) and the impairments recognized during 2009 for our New Castle and Indian River plants.

(i) Capitalization of Interest Expense.

We capitalize interest on capital projects greater than $10 million and under development for one year or more. During 2009, 2008 and 2007, we capitalized $23 million, $17 million and $4 million of interest expense, respectively, relating primarily to environmental capital expenditures for SO_2 emission reductions at the Cheswick and Keystone plants.

(j) Cash and Cash Equivalents.

We record all highly liquid short-term investments with maturities of three months or less as cash equivalents.

(k) Restricted Cash.

Restricted cash includes cash at certain subsidiaries, the distribution or transfer of which is restricted by financing and other agreements.

(l) Inventory.

We value fuel inventories at the lower of average cost or market. We reduce these inventories as they are used in the production of electricity or sold. During 2009, 2008 and 2007, we recorded $101 million,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$40 million and $5 million, respectively, for lower of average cost or market valuation adjustments in cost of sales. We value materials and supplies at average cost. We remove these inventories when they are used for repairs, maintenance or capital projects. Sales of fuel inventory are classified as operating activities in the consolidated statement of cash flows.

	December 31,	
	2009	2008
	(in millions)	
Materials and supplies, including spare parts	$ 187	$ 159
Coal	97	90
Natural gas	14	25
Heating oil	34	41
Total inventory	$ 332	$ 315

(m) Environmental Costs.

We expense environmental expenditures related to existing conditions that do not have future economic benefit. We capitalize environmental expenditures for which there is a future economic benefit. We record liabilities for expected future costs, on an undiscounted basis, related to environmental assessments and/or remediation when they are probable and can be reasonably estimated. See note 16(b).

(n) Asset Retirement Obligations.

Our asset retirement obligations relate to future costs primarily associated with dismantling power plants and coal ash disposal site closures. Changes in asset retirement obligations, classified in other long-term liabilities, are:

	2009	2008
	(in millions)	
Balance, beginning of period	$ 19	$ 21
Revisions in estimated cash flows	8(1)	(1)
Payments	(4)	(1)
Accretion expense	2	2
Other, net	1	(2)
Balance, end of period	$ 26	$ 19

(1) Primarily relates to changes in timing of expected closures and higher estimated costs.

As of December 31, 2009 and 2008, we have $20 million and $18 million, respectively (classified in other long-term assets) on deposit with the state of Pennsylvania to guarantee our obligation related to future closures of coal ash disposal landfill sites. See note 16(b).

(o) Repair and Maintenance Costs for Power Generation Assets.

We expense repair and maintenance costs as incurred.

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(p) Deferred Financing Costs.

We incur costs, which are deferred and amortized over the life of the debt, in connection with obtaining financings. See note 7. Changes in deferred financing costs, classified in other long-term assets, are:

	2009	2008	2007
		(in millions)	
Balance, beginning of period	$ 54	$ 62	$ 86
Capitalized			31
Amortized	(7)	(7)	(9)
Accelerated amortization/write-offs(1)	(5)	(1)	(41)
Channelview deconsolidation			(5)
Balance, end of period	$ 42	$ 54	$ 62

(1) Amounts are considered a portion of the net carrying value of the related debt and are expensed when accelerated as a component of debt extinguishments.

(q) New Accounting Pronouncements Adopted.

FASB Codification. The Financial Accounting Standards Board s Accounting Standards Codification became effective for us in the third quarter of 2009. The Codification brings together in one place all authoritative GAAP except for rules, regulations and interpretative releases of the Securities and Exchange Commission which are also authoritative GAAP for us. This change did not materially affect our consolidated financial statements.

Measuring Liabilities at Fair Value. This guidance provides clarification for measuring liabilities at fair value when there may be a lack of observable market information and requires an entity under those circumstances to employ techniques that use (a) the quoted price of the identical liability when traded as an asset, (b) quoted prices for similar liabilities or similar liabilities when traded as assets or (c) another valuation technique consistent with the fair value measurement principles such as an income approach or a market approach. This change did not impact our consolidated financial statements. See note 2(d).

Disclosures about Plan Assets. This guidance requires enhanced disclosures regarding investment policies and strategies for our benefit plan assets as well as information about fair value measurements of plan assets. See note 11.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. This guidance provides direction on how to determine the fair value of certain assets and liabilities when there has been a significant decrease in the volume and level of activity for an asset or liability compared with normal market activity for the asset or liability. This guidance did not have a significant impact on our consolidated financial statements since the markets in which we purchase and sell commodities and derivative instruments are not distressed. See notes 2(d) and 6.

(r) New Accounting Pronouncements Not Yet Adopted.

Improving Financial Reporting Around Variable Interest Entities. For 2007, 2008 and 2009, we do not have any off-balance sheet arrangements to report under requirements effective prior to 2010. In connection with related amended accounting guidance for variable interest entities, which is effective as of January 1, 2010, we are assessing (a) our REMA leases for our interests in the Conemaugh, Keystone and Shawville plants (see note 15(a)) and (b) the tolling agreement at the Vandolah plant whereby we provide our own fuel for operations and take all the power generated (see note 15(a)). If (a) the single power plant legal entities, which own the plants or our interests in the plants are determined to be variable interest entities, (b) our contracts are determined to be or contain variable interests in those entities and (c) we have the power to direct the activities of the entities that most significantly impact the entities economic performance and the obligation to absorb losses of or the right to receive benefits from the entities that could be significant to the

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entities, we would be required to consolidate the entities, which could materially change our future financial statements.

Improving Disclosures about Fair Value Measurements. Effective for our first quarter 2010 Form 10-Q, this guidance provides for disclosures of significant transfers in and out of Levels 1 and 2. In addition, it clarifies existing disclosure requirements regarding inputs and valuation techniques as well as the appropriate level of disaggregation for fair value measurements disclosures. Effective for the 2011 financial statements, this guidance provides for disclosures of activity on a gross basis within the Level 3 reconciliation. These changes will only affect our disclosures.

(3) Related Party Transactions

Indemnities and Releases. As part of our separation from CenterPoint, we agreed to indemnify our former parent company for liabilities associated with the business we acquired. See notes 14(d), 15(b) and 16(c).

(4) Long-Lived Assets Impairments

We periodically evaluate the recoverability of our long-lived assets (property, plant and equipment and intangible assets), which involves significant judgment and estimates, when there are certain indicators (see below) that the carrying value of these assets may not be recoverable. As of December 31, 2009, we had $4.9 billion of long-lived assets. This estimate affects all segments, which hold 99% of our total net property, plant and equipment and net intangible assets. Our East Coal segment holds the largest portion of our net property, plant and equipment and net intangible assets at 59% of our consolidated total. See notes 2(g) and 5.

We evaluate our long-lived assets when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Examples of such events or changes in circumstances are:

- a significant decrease in the market price of a long-lived asset
- a significant adverse change in the manner an asset is being used or its physical condition
- an adverse action by a regulator or legislature or an adverse change in the business climate
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset
- a current-period loss combined with a history of losses or the projections of future losses
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life

When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. Each plant (including its property, plant and equipment and intangible assets) was determined to be its own group.

The determination of impairment is a two-step process, the first of which involves comparing the undiscounted cash flows to the carrying value of the asset. If the carrying value exceeds the undiscounted cash flows, the fair value of the asset must be determined. The fair value of an asset is the price that would be received from a sale of the asset in an orderly transaction between market participants at the measurement date. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, when available. In the absence of quoted prices for identical or similar assets, fair value is estimated using various internal and external valuation methods. These methods include discounted cash flow analyses and reviewing available information on comparable transactions.

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Key Assumptions. The following summarizes some of the most significant estimates and assumptions used in evaluating our plant level undiscounted cash flows. The ranges for the fundamental view assumptions are to account for variability by year and region.

	December 31, 2009
Undiscounted Cash Flow Scenarios Weightings:	
5-year market forecast with escalation(1)(2)	50%
5-year market forecast with fundamental view(1)	50%
Range of Assumptions in Fundamental View:	
Demand for power growth per year	1%-2%
After-tax rate of return on new construction(3)	6.5%-9.5%
Spread between natural gas and coal prices, $/MMBTU(4)	$3-$5

(1) For each scenario, the first five years of cash flows are the same.

(2) We assumed an annual 2.5% escalation percentage beyond year five.

(3) The low to mid part of the range represents natural gas-fired plants required returns and the mid to high part of the range represents coal-fired and nuclear plants required returns.

(4) Natural gas and coal prices are prior to transportation costs.

Our Indian River plant is located in Florida where the merchant power market is primarily bilateral. This plant had historically generated most of its revenues and gross margin from power purchase agreements, which expired in 2009. Therefore, we believed it was more meaningful to develop different assumptions for our Indian River plant. We estimated the cash flows and probability weightings around five different scenarios. Four of the scenarios (weighted for a combined 70%) included power purchase agreements for varying time periods and ultimate sale of the plant and the remaining scenario (weighted at 30%) included a sale only.

We estimate the undiscounted cash flows of our plants based on a number of subjective factors, including: (a) appropriate weighting of undiscounted cash flow scenarios, as shown in the table above, (b) forecasts of future power generation margins, (c) estimates of our future cost structure, (d) environmental assumptions, (e) time horizon of cash flow forecasts and (f) estimates of terminal values of plants, if necessary, from the eventual disposition of the assets. We did not include the cash flows associated with our economic hedges in our PJM region (East Coal and East Gas segments) as these cash flows are not specific to any one plant.

Under the 5-year market forecast with escalation scenario, we use the following data: (a) forward market curves for commodity prices as of December 18, 2009 for the first five years, (b) cash flow projections through the plant s estimated remaining useful life and (c) escalation factor of cash flows of 2.5% per year after year five.

Under the 5-year market forecast with fundamental view scenario, we model all of our plants and those of others in the regions in which we operate, using these assumptions: (a) forward market curves for commodity prices as of December 18, 2009 for the first five years; (b) ranges shown in the table above used in developing our fundamental view beyond five years; (c) the markets in which we operate will continue to be deregulated and earn margins based on forward or projected market prices; (d) projected market prices for energy and capacity will be set by the forecasted available supply and level of forecasted demand new supply will enter markets when market prices and associated returns, including any assumed subsidies for renewable energy, are sufficient to achieve minimum return requirements; (e) minimum return requirements on future construction of new generation facilities, as shown in the table above, will likely be driven or influenced by utilities, which we expect will have a lower cost of capital than merchant generators; (f) various ranges of environmental regulations, including those for SO_2, NO_x and greenhouse gas emissions; and (g) cash flow projections through the plant s estimated remaining useful life.

Fair Value. Generally, fair value will be determined using an income approach or a market-based approach. Under the income approach, the future cash flows are estimated as described above and then discounted using a risk-adjusted rate. Under a market-based approach, we may also consider prices of similar assets, consult with brokers or employ other valuation techniques.

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The following are key assumptions used in our fair value analyses for our two plants for which the undiscounted cash flows did not exceed the net book value of the long-lived assets.

	New Castle	Indian River
Valuation approach weightings:		
Income approach	100%	100%
Market-based approach	0%	0%
Risk-adjusted discount rate for the estimated cash flows	15%	15%

We only used the income approach as we believe no relevant market data exists for these two plants for which we were required to estimate fair value. The discount rates reflect the uncertainty of the plants cash flows and their inability to support meaningful amounts of debt, and was determined considering factors such as the potential for future capacity and power purchase agreement revenues and regulatory, commodity and macroeconomic conditions.

We determined that our New Castle plant, which consists of property, plant and equipment, was impaired by $120 million as of December 31, 2009. This impairment was primarily due to the expected levels of low profitability given that the plant would likely require significant environmental capital expenditures in the future under existing and likely environmental regulations. We determined that our Indian River plant, which consists of property, plant and equipment and various intangible assets (water rights, permits and emission allowances), was impaired by $91 million as of December 31, 2009. This impairment was primarily due to a power purchase agreement with a utility in Florida expiring in December 2009 and because of the uncertainty that a replacement power purchase agreement will occur for the foreseeable future. We believe the remaining net book values of $44 million for New Castle and $52 million for Indian River represent our best estimates of fair values as of December 31, 2009.

Certain disclosures are required about nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. This applies to our long-lived assets for which we were required to determine fair value. A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. See note 2(d) for further discussion about the three levels. These assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and affects the valuation of fair value and the assets placement within the fair value hierarchy levels.

	December 31, 2009			2009 Impairment
	Level 1	Level 2	Level 3	Charges
		(in millions)		
New Castle property, plant and equipment[1]	$	$	$ 44	$ 120
			52	91

Indian River property, plant and equipment, water rights, permits and emission allowances[2]				
Total	$	$	$ 96	$ 211

(1) New Castle is in our East Coal segment.

(2) Indian River is in our Other segment.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether long-lived assets are recoverable or whether impairment exists are subject to high degree of uncertainty. Different assumptions as to power prices, fuel costs, our future cost structure, environmental assumptions and remaining useful lives and ultimate disposition values of our plants would result in estimated future cash flows that could be materially different than those considered in the recoverability assessments as of December 31, 2009 and could result in having to estimate the fair value of other plants.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Use of a different risk-adjusted discount rate would result in fair value estimates for the two plants for which we recorded an impairment in 2009 that could be materially greater than or less than the fair value estimates as of December 31, 2009. Any future fair value estimates for our New Castle and Indian River long-lived assets that are greater than the fair value estimates as of December 31, 2009 will not result in reversal of the 2009 impairment charges.

(5) Intangible Assets

(a) Goodwill.

The following table shows the changes in goodwill for 2008 (in millions):

As of January 1, 2008	$	327
Goodwill impairment		(305)
Other changes		(22)(1)
As of December 31, 2008	$	

(1) Relates to the sale of our Channelview plant in July 2008 ($5 million) and the sale of our Bighorn plant in October 2008 ($17 million). See notes 21 and 22.

As of December 31, 2009 and 2008, we had $39 million and $47 million, respectively, of goodwill that is deductible for United States income tax purposes in future periods.

We tested goodwill for impairment on an annual basis in April (through 2008), and more often if events or circumstances indicated there may have been impairment. We historically (through the second quarter of 2009) had two reporting segments: wholesale energy and retail energy. Goodwill impairment testing was performed at the reporting unit level, which was consistent with our reporting segments. We continually assessed whether any indicators of impairment existed, which required a significant amount of judgment. Such indicators may have included a sustained significant decline in our share price and market capitalization; a decline in our expected future cash flows; a significant adverse change in legal factors or in the business climate; unanticipated competition; overall weaknesses in our industry; and slower growth rates. Any adverse change in these factors could have had a significant impact on the recoverability of goodwill and could have had a material impact on our consolidated financial statements.

During April 2008, we tested goodwill for impairment and determined that no impairments existed.

During the third and fourth quarters of 2008, given adverse changes in the business climate and the credit markets, our market capitalization being lower than our book value during all of the fourth quarter and extending into 2009, our review of strategic alternatives to enhance stockholder value and reductions in our expected near-term cash flows from operations, we reviewed our goodwill for impairment. We concluded that no goodwill impairments occurred as of September 30, 2008. As discussed below, as of December 31, 2008, we concluded that our historical wholesale energy segment s goodwill of $305 million was impaired.

Goodwill was reviewed for impairments based on a two-step test. In the first step, we compared the fair value of each reporting unit with its net book value. We applied judgment in determining the fair value of our reporting units for purposes of performing our goodwill impairment tests because quoted market prices for our reporting units were not available. In estimating the fair values of the reporting units, we used a combination of an income approach and a market-based approach.

Income approach We discounted the expected cash flows of each reporting unit. The discount rate used represented the estimated weighted average cost of capital, which reflected the overall level of inherent risk involved in our operations and cash flows and the rate of return an outside investor would expect to earn. To estimate cash flows beyond the final year of our model, we applied a terminal value multiple to the final year EBITDA.

Market-based approach We used the guideline public company method, which focused on comparing our risk profile and growth prospects to select reasonably similar/guideline publicly traded companies.

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RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We also used a public transaction method, which focused on exchange prices in actual transactions as an indicator of fair value.

In weighting the results of the various valuation approaches, prior to the fourth quarter of 2008, we placed more emphasis on the income approach, using management s future cash flow projections for each reporting unit and risk-adjusted discount rates. As our earnings outlook declined, our earnings variability increased and our market capitalization declined significantly in 2008, we increased the weighting of the estimates of fair value of our reporting units determined by the market-based approaches. Further, the aggregate estimated fair value of our reporting units was compared to our total market capitalization, adjusted for a control premium. A control premium was added to the market capitalization to reflect the value that existed with having control over an entire entity.

If the estimated fair value of the reporting unit was higher than the recorded net book value, no impairment was considered to exist and no further testing was required. However, if the estimated fair value of the reporting unit was below the recorded net book value, a second step must be performed to determine the goodwill impairment required, if any. In the second step, the estimated fair value from the first step was used as the purchase price in a hypothetical acquisition of the reporting unit, which was then allocated to the reporting unit s assets and liabilities in accordance with purchase accounting rules. The residual amount of goodwill that resulted from this hypothetical purchase price allocation was compared to the recorded amount of goodwill for the reporting unit, and the recorded amount was written down to the hypothetical amount, if lower.

Estimation of our Historical Wholesale Energy Reporting Unit s Fair Value. We estimated the fair value of our wholesale energy reporting unit based on a number of subjective factors, including: (a) appropriate weighting of valuation approaches, as discussed above, (b) projections about the future power generation margins, (c) estimates of our future cost structure, (d) environmental assumptions, (e) risk-adjusted discount rates for our estimated cash flows, (f) selection of peer group companies for the public company market approach, (g) required level of working capital, (h) assumed EBITDA multiple for terminal values and (i) time horizon of cash flow forecasts.

As part of our process, we developed 15-year forecasts of earnings and cash flows, assuming that demand for power grows at the rate of two percent a year. We modeled all of our power generation facilities and those of others in the regions in which we operate, using these assumptions: (a) the markets in which we operate will continue to be deregulated and earn a market return; (b) there will be a recovery in electricity margins over time such that companies building new generation facilities can earn a reasonable rate of return on their investment, which implies that margins and therefore cash flows in the future would be better than they are today because market prices will need to rise high enough to provide an incentive for new plants to be built, and the entire market will realize the benefit of those higher margins and (c) the long-term returns on future construction of new generation facilities will likely be driven by integrated utilities, which we expect will have a lower cost of capital than merchant generators, which implies that the revenues and margins described in (b) above will be at the level of return required for a regulated entity instead of a deregulated company. We assumed that the after-tax rate of return on new construction was 7.5%.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our assumptions for each of our goodwill impairment assessments during 2007 and 2008:

	April 2007	April 2008	September 2008	December 2008
Income approach assumptions				
EBITDA multiple for terminal values[1]	8.0	8.0	7.0	7.0
Risk-adjusted discount rate for our estimated cash flows[2]	9.5%	10.0%	11.0%	13.0%
Market-based approach assumptions				
EBITDA multiple for publicly traded company	8	8	5	6
Valuation approach weightings[3]				
Income approach	70%	60%	80%	25%
Market-based approach	30%	40%	20%	75%

(1) Changed primarily due to market factors affecting peer company comparisons.

(2) Increased primarily due to capital structure of peer company comparisons and increased required rate of return on debt and equity capital of peer companies.

(3) Changed primarily due to increased focus on market-based approaches. See discussion above.

Based on our analysis, we concluded that the wholesale energy reporting unit did not pass the first step as of December 31, 2008, primarily due to lower expected cash flows due to the adverse business climate, significantly lower expected exchange transaction values due to credit market disruptions which would make it difficult for transactions to occur and increase the price of those transactions and significantly lower valuations for our peer companies. In addition, when we compared the aggregate of our fair value estimates of both reporting units to our market capitalization, including a control premium, we determined that the market participants views of our fair value had also declined significantly.

We then performed the second step of the impairment test, which required an allocation of the fair value as the purchase price in a hypothetical acquisition of the reporting unit. The significant hypothetical purchase price allocation adjustments made to the assets and liabilities of our wholesale energy reporting unit consisted of the following:

Adjusting the carrying value of our property, plant and equipment to values that would be expected in the current credit and market environment

Adjusting the carrying value of our emission allowances, which then traded at amounts significantly higher than our book value

Adjusting the carrying value of our debt, which had a lower fair value than our book value

Adjusting deferred income taxes for changes in the balances listed above

After making these hypothetical adjustments, no residual value remained for a goodwill allocation resulting in the impairment of our historical wholesale energy reporting unit s goodwill net carrying amount of $305 million as of December 31, 2008.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) Other Intangibles.

	Remaining Weighted Average Amortization Period (Years)	December 31, 2009 Carrying Amount	2009 Accumulated Amortization	2008 Carrying Amount	2008 Accumulated Amortization
		(in millions)			
SO_2 emission allowances(1)(2)	(1)	$ 140(3)	$ (14)(3)	$ 178(4)	$ (51)(4)
NO_x emission allowances(1)(5)	(1)	142(3)	(2)(3)	145(4)	(4)
Power generation site permits(6)	23	41(7)	(7)(7)	73	(14)
Water rights(6)	5	5(8)	(8)	67	(18)
Other		1			
Total		$ 329	$ (23)	$ 463	$ (83)

(1) Amortized to amortization expense on a units-of-production basis. As of December 31, 2009, we have recorded (a) SO_2 emission allowances through the 2039 vintage year and (b) NO_x emission allowances through the 2039 vintage year.

(2) During 2009, 2008 and 2007, we purchased $19 million, $48 million and $89 million, respectively, of SO_2 emission allowances.

(3) During 2009, we wrote off the fully amortized carrying amount and accumulated amortization for SO_2 and NO_x emission allowances surrendered of $56 million and $6 million, respectively.

(4) During 2008, we wrote off the fully amortized carrying amount and accumulated amortization for SO_2 and NO_x emission allowances surrendered of $313 million and $200 million, respectively.

(5) During 2009, 2008 and 2007, we purchased $3 million, $13 million and $3 million, respectively, of NO_x emission allowances.

(6) Amortized to amortization expense on a straight-line basis over the estimated lives.

(7) During 2009, we recognized an impairment charge of $21 million relating to permits at our Indian River plant. See note 4.

(8) During 2009, we recognized an impairment charge of $43 million relating to water rights at our Indian River plant. See note 4.

	2009	2008	2007
		(in millions)	
Amortization of emission allowances	$ 24	$ 68	$ 110
Amortization of power generation site permits, water rights and other	4	4	5
Total amortization expense	$ 28	$ 72	$ 115

Estimated amortization expense based on our intangibles as of December 31, 2009 for the next five years is (in millions):

2010	$ 17(1)
2011	15(1)
2012	15(1)
2013	14(1)
2014	14(1)

(1) These amounts do not include expected amortization expense of emission allowances not purchased as of December 31, 2009.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) Derivatives and Hedging Activities

We use derivative instruments to manage operational or market constraints and to increase return on our generation assets. See note 2(e).

As of December 31, 2009 and 2008, we do not have any designated cash flow hedges. Amounts included in accumulated other comprehensive loss are:

	December 31, 2009	
	At the End of the Period	Expected to be Reclassified into Results of Operations in Next 12 Months
	(in millions)	
De-designated cash flow hedges, net of tax(1)(2)	$ 34	$ 14

(1) No component of the derivatives gain or loss was excluded from the assessment of effectiveness.

(2) During 2009, 2008 and 2007, $0 was recognized in our results of operations as a result of the discontinuance of cash flow hedges because it was probable that the forecasted transaction would not occur.

As of December 31, 2009, our commodity derivative assets and liabilities include amounts for non-trading and trading activities as follows:

	Derivative Assets		Derivative Liabilities		Net Derivative Assets
	Current	Long-Term	Current	Long-Term	(Liabilities)
			(in millions)		
Non-trading	$ 66	$ 53	$ (105)	$ (61)	$ (47)
Trading	66		(47)		19
Total derivatives	$ 132	$ 53	$ (152)	$ (61)	$ (28)

We have the following derivative commodity contracts outstanding as of December 31, 2009:

Commodity	Unit[1]	Notional Volumes[2] Current	Long-term
		(in millions)	
Power	MWh	(5)	(6)
Capacity energy	MWh	(2)	(1)
Natural gas(3)	MMBTU	(3)	24
Natural gas basis	MMBTU	(5)	
Coal	MMBTU	122	176

(1) MWh is megawatt hours and MMBTU is million British thermal units.

(2) Negative amounts indicate net forward sales.

(3) Includes current and long-term volumes related to purchases of put options.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The income (loss) associated with our energy derivatives during 2009 is:

Derivatives not Designated as Hedging Instruments(1)	Revenues	Cost of Sales
	(in millions)	
Non-Trading Commodity Contracts:		
Unrealized(2)	$ (44)	$ 77
Realized(3)(4)(5)	371	(217)
Total non-trading	$ 327	$ (140)
Trading Commodity Contracts:		
Unrealized(2)	$	$ (11)
Realized(3)		21
Total trading	$	$ 10

(1) We had interest rate swaps that were liquidated in 2002 and the related deferred losses in accumulated other comprehensive loss are being amortized into interest expense through 2012. An insignificant amount was amortized during 2009 and 2008. We amortized $5 million during 2007.

(2) As discussed in note 2(e), during 2007, we de-designated our remaining cash flow hedges; the amount reflected here subsequent to that time relates to previously measured ineffectiveness reversing due to settlement of the derivative contracts.

(3) Does not include realized gains or losses associated with cash month transactions, non-derivative transactions or derivative transactions that qualify for the normal purchase/normal sale exception.

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

(5) Includes gains or losses from de-designated cash flow hedges reclassified from accumulated other comprehensive loss due to settlement of the derivative contracts. See note 2(e).

Trading Activities. Prior to March 2003, we engaged in proprietary trading activities. Trading positions entered into prior to our decision to exit this business are being closed on economical terms or are being retained and settled over the contract terms. In addition, we have current transactions relating to non-core asset management, such as gas storage and transportation contracts not tied to generation assets, which are classified as trading activities. The income (loss) associated with these transactions is:

	2009	2008	2007
	(in millions)		
Revenues	$ 1	$ (8)	$ 1
Cost of sales	19	33	18
Total[(1)]	$ 20	$ 25	$ 19

(1) Includes realized and unrealized gains and losses on both derivative instruments and non-derivative instruments.

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RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) Debt

(a) Overview.

	December 31, 2009			December 31, 2008		
	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:						
RRI Energy:						
Senior secured revolver due 2012	1.98%	$	$	3.18%	$	$
Senior secured notes due 2014	6.75	279		6.75	498(2)	
Senior unsecured notes due 2014	7.625	575		7.625	575	
Senior unsecured notes due 2017	7.875	725		7.875	725	
Subsidiary Obligations:						
Orion Power Holdings, Inc. senior notes due 2010 (unsecured)	12.00		400	12.00	400	
PEDFA(3) fixed-rate bonds due 2036	6.75	371		6.75	408(4)	
Total facilities, bonds and notes		1,950	400		2,606	
Other:						
Adjustment to fair value of debt(5)			5		4	13
Total other debt			5		4	13
Total debt		$ 1,950	$ 405		$ 2,610(6)	$ 13

(1) The weighted average stated interest rates are as of December 31, 2009 or 2008.

(2) Excludes $169 million classified as discontinued operations. See note 23.

(3) PEDFA is the Pennsylvania Economic Development Financing Authority. These bonds were issued for our Seward plant.

(4) Excludes $92 million classified as discontinued operations. See note 23.

(5) Debt acquired in the acquisition of Orion Power Holdings, Inc. (Orion Power Holdings) and subsidiaries (Orion Power) was adjusted to fair value as of the acquisition date. Included in interest expense is amortization of $12 million, $11 million and $11 million for valuation adjustments for debt during 2009, 2008 and 2007, respectively.

(6) Excludes $261 million classified as discontinued operations. See note 23.

Amounts borrowed and available for borrowing under our revolving credit agreements as of December 31, 2009 are:

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount
		(in millions)		
RRI Energy senior secured revolver due 2012	$ 500	$	$	$ 500
RRI Energy letter of credit facility due 2014	250		81	169
Total	$ 750	$	$ 81	$ 669

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt maturities as of December 31, 2009 are:

	RRI Energy	RRI Energy Consolidated
	(in millions)	
2010	$	$ 400
2011		
2012		
2013		
2014	854	854
2015 and thereafter	725	1,096
	$ 1,579	$ 2,350

(b) Significant Financing Activity.

2009 Debt Reduction Activity. We completed the following secured debt reduction activities:

Senior secured 6.75% notes:

$127 million through cash tender offer

$92 million through open market purchases

These transactions resulted in net loss on extinguishments of $6 million related to the difference between the amounts paid and the net carrying value of the debt

PEDFA fixed-rate bonds:

$35 million through open market purchases

$2 million through cash tender offer

These transactions resulted in net loss on extinguishments of $2 million related to the difference between the amounts paid and the net carrying value of the debt

$261 million of our senior secured 6.75% notes ($169 million) and PEDFA fixed-rate bonds ($92 million) purchased with the net proceeds from the sale of our Texas retail business and classified as discontinued operations (see note 23)

2007 Financing Activity. We completed a refinancing in June 2007, the components of which included:

Downsize of:

- $700 million to $500 million senior secured revolver and extension of maturity from 2009 to 2012
- $300 million to $250 million senior secured letter of credit facility and extension of maturity from 2010 to 2014

Issuance of:

- $575 million 7.625% senior unsecured notes due 2014
- $725 million 7.875% senior unsecured notes due 2017

Repayment of:

- $521 million 9.25% senior secured notes due 2010
- $537 million 9.50% senior secured notes due 2013
- $400 million senior secured term loan due 2010

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Credit Facilities and Debt.

Senior Secured Revolver and Letter of Credit Facility (the June 2007 credit facilities). We entered into the June 2007 credit facilities, which replaced our December 2006 credit facilities. The senior secured revolver bears interest at the London Inter Bank Offered Rate (LIBOR) plus 1.75% or a base rate plus 0.75%. Our revolving credit facility and letter of credit facility provide for the issuance of up to $500 million and $250 million of letters of credit, respectively.

The June 2007 credit facilities restrict our ability to, among other actions, (a) encumber our assets, (b) enter into business combinations or divest our assets, (c) incur additional debt or engage in sale and leaseback transactions, (d) pay dividends or pay subordinated debt, (e) enter into some transactions with affiliates, (f) materially change our business or (g) repurchase capital stock. When there are any revolving loans or revolving letters of credit outstanding under our June 2007 credit facilities, our consolidated net secured debt must not exceed four times adjusted net earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization (consolidated secured leverage ratio). As of December 31, 2009, there were no revolving loans or revolving letters of credit outstanding.

The June 2007 credit facilities are guaranteed by and secured by the assets and stock of some of our subsidiaries. See note 18.

Senior Secured 6.75% Notes. The senior secured notes are guaranteed by and secured by the assets and stock of some of our subsidiaries. See note 17. If our June 2007 credit facilities become unsecured and certain credit ratios are achieved for two consecutive quarters, the senior secured notes will become unsecured. Upon a change of control, the notes require that an offer to purchase the notes be made at a purchase price of 101% of the principal amount. The senior secured notes have negative covenants similar to the negative covenants in our June 2007 credit facilities. During 2009, 2008 and 2007, we repurchased $219 million, $45 million and $38 million, respectively.

Senior Unsecured 7.625% and 7.875% Notes. In June 2007, we issued $575 million of 7.625% senior unsecured notes due 2014 and $725 million of 7.875% senior unsecured notes due 2017. These notes are unsecured obligations and not guaranteed. The unsecured notes restrict our ability to encumber our assets. Upon a change of control, the notes require that an offer to purchase the notes be made at a purchase price of 101% of the principal amount. The proceeds of this issuance were used to repay the tendered 9.25% and 9.50% senior secured notes and a portion of the senior secured term loan.

Senior Unsecured 9.25% and 9.50% Notes. In June 2007, we completed a tender offer to purchase for cash any and all of the outstanding 9.25% senior secured notes due 2010 and 9.50% senior secured notes due 2013. We also solicited consents to (a) amend the applicable indentures governing the notes to eliminate substantially all of the restrictive covenants, (b) amend certain events of default, (c) modify other provisions contained in the indentures and (d) release the collateral securing the notes. Approximately 94.81% of the 2010 note holders and 97.73% of the 2013 note holders accepted the tender offer and agreed to the consents. We paid a cash premium of $50 million and a consent solicitation fee of $21 million to the note holders who tendered during 2007.

In July 2007, we called the remaining $29 million of our 2010 notes. In July 2008, we called the remaining $13 million of our 2013 notes.

Orion Power Holdings Senior Notes. These notes were recorded at a fair value of $479 million upon the acquisition of Orion Power. The $79 million premium is being amortized to interest expense over the life of the notes. The senior notes are senior unsecured obligations of Orion Power Holdings, are not guaranteed by any of Orion Power Holdings subsidiaries and are non-recourse to RRI Energy. The senior notes have covenants that restrict the ability of Orion Power Holdings and its subsidiaries to, among other actions, (a) pay dividends or pay subordinated debt, (b) incur indebtedness or issue preferred stock, (c) make investments, (d) divest assets, (e) encumber its assets, (f) enter into transactions with affiliates, (g) engage in unrelated businesses and (h) engage in sale and leaseback transactions. As of December 31, 2009, conditions

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

under these covenants that allow the payment of dividends by Orion Power Holdings were not met. As of December 31, 2009, the adjusted net assets of Orion Power that are restricted to RRI Energy are $1.3 billion.

PEDFA Fixed-Rate Bonds. RRI Energy Wholesale Generation, LLC partially financed the construction of its Seward power plant with proceeds from the issuance of tax-exempt revenue bonds by PEDFA. These bonds are guaranteed by RRI Energy and each guarantee is secured by the same collateral as our senior secured notes and has covenants similar to the June 2007 credit facilities. If our June 2007 credit facilities become unsecured and certain ratios are achieved for two consecutive quarters, the PEDFA bonds will become secured by only certain assets of our Seward power plant. Upon a change of control, the guarantees require that an offer to purchase the bonds be made at a purchase price of 101% of the principal amount. During 2009, we purchased $37 million.

(8) Stockholders Equity

The following describes our capital stock activity:

	Common Stock (shares in thousands)
As of January 1, 2007	337,623
Issued to benefit plans	5,562
Issued for warrants	1,384
Issued for converted debt	11
As of December 31, 2007	344,580
Issued to benefit plans	1,064
Issued for warrants	3,958
Issued for converted debt	211
As of December 31, 2008	349,813
Issued to benefit plans	2,973
As of December 31, 2009	352,786

(9) Earnings (Loss) Per Share

The amounts used in the basic and diluted earnings (loss) per common share computations are the same.

	2009	2008 (in millions)	2007
Loss from continuing operations (basic and diluted)	$ (479)	$ (110)	$ (202)

	2009	2008	2007
	(shares in thousands)		
Weighted average shares outstanding (basic and diluted)	351,396	347,823	342,467

We excluded the following items from diluted earnings (loss) per common share due to the anti-dilutive effect:

	2009	2008	2007
	(shares in thousands, dollars in millions)		
Shares excluded from the calculation of diluted earnings/loss per share	537(1)	5,290(2)	10,234(2)
Shares excluded from the calculation of diluted earnings/loss per share because the exercise price exceeded the average market price	4,729(3)	2,270(3)	2,005(3)

(1) Primarily includes stock options and restricted stock.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Primarily includes stock options and warrants.

(3) Includes stock options.

(10) Stock-Based Incentive Plans

Overview of Plans. The Compensation Committee of the Board of Directors administers our stock-based incentive plans. The RRI Energy, Inc. 2002 Long-Term Incentive Plan and the RRI Energy, Inc. 2002 Stock Plan permit us to grant various stock-based incentive awards to officers, key employees and directors. Awards may include stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, cash awards and stock awards.

As of December 31, 2009, 37 million shares are authorized for issuance under our stock-based incentive plans. No more than 25% of these shares can be granted as stock-based awards other than options. We have generally issued new shares when stock options are exercised and for other equity-based awards.

Summary. Compensation costs related to share-based transactions are recognized in the financial statements based on estimated fair values at the grant dates. We did not capitalize any stock-based compensation costs as an asset during 2009, 2008 and 2007. Our compensation expense for our stock-based incentive plans was:

	2009	2008 (in millions)	2007
Stock-based incentive plans compensation expense (pre-tax)	$ 9	$ 9	$ 20
Income tax impact (before impact of the valuation allowances)	$ (2)	$ (2)	$ (7)

We use the alternative method to calculate excess tax benefits available to absorb tax deficiencies.

Valuation Data. Below is the description of the methods used to estimate the fair value of our various awards.

Time-based stock options	Black-Scholes option-pricing model value on the grant date
Time-based restricted stock[1]	Market price of our common stock on the grant date
Time-based cash units[2]	Market price of our common stock on each reporting measurement date
Performance-based options[3]	Black-Scholes option-pricing model value on each reporting measurement date until accounting grant date
Market-based cash units[2]	Monte Carlo simulation valuation model value on each reporting measurement date

Employee stock purchase plan	Black-Scholes option-pricing model value on the first day of the offering period

(1) Restricted stock and restricted stock units are referred to as restricted stock.

(2) These are liability-classified awards.

(3) No awards were granted during 2009, 2008 and 2007.

Time-Based Stock Options. We grant time-based stock options to officers, key employees and directors at an exercise price equal to the market value of our common stock on the grant date. Generally, options vest 33.33% per year for three years and have a term of 10 years. Compensation expense is measured at fair value on the grant date, net of estimated forfeitures, and expensed on a straight-line basis over the requisite service period for the entire award.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized time-based option activity is:

	2009			
	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Terms (Years)	Aggregate Intrinsic Value (in millions)
Beginning of period	5,718,587	$ 15.58	4	$ 2
Exercised	(1,352,237)(1)	4.57		
Forfeited	(154,252)	20.75		
Expired	(860,768)	20.97		
End of period	3,351,330(2)(3)	18.40	3	1
Exercisable at the end of period	3,025,856	17.97	2	1

(1) Received proceeds of $6 million. Intrinsic value was $3 million on the exercise dates. No tax benefits were realized in 2009 due to our net operating loss carryforwards.

(2) We estimate that 48,018 of these will be forfeited.

(3) As of December 31, 2009, the total compensation cost related to nonvested time-based stock options not yet recognized and the weighted-average period over which it is expected to be recognized is $2 million and one year, respectively.

	2008	2007
	(in millions, except per unit amounts)	
Weighted average grant date fair value of the time-based options granted	$ 9.88	$ 7.32
Proceeds from exercise of time-based options	2	21
Intrinsic value of exercised time-based options	3	26
Tax benefits realized	(1)	(1)

(1) None realized due to our net operating loss carryforwards.

Our time-based stock option awards are based on the following weighted average assumptions and resulting fair value. No time-based stock option awards were granted during 2009.

	2008
Expected term in years(1)	6
Estimated volatility(2)	38.37%
Risk-free interest rate	3.17%
Dividend yield	0%
Weighted-average fair value	$ 9.88

(1) The expected term is based on a binomial lattice model.

(2) We estimate volatility based on historical and implied volatility of our common stock.

Time-Based Restricted Stock Awards. We grant time-based restricted stock awards to officers, key employees and directors. In general, these awards vest, subject to the participant s continued employment, three years from the grant date. In June 2009, the Compensation Committee of our Board of Directors granted 817,030 time-based restricted stock units (which are included in the time-based restricted stock awards disclosure below) to employees under our stock and incentive plans. The awards will vest in June 2012. Compensation expense is measured at fair value on the grant date, net of estimated forfeitures, and expensed on a straight-line basis over the requisite service period.

RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized restricted stock award activity is:

	2009	
	Shares	Weighted Average Grant Date Fair Value
Beginning of period	1,168,582	$ 16.08
Granted	985,898	5.09
Vested	(499,646)[1]	8.94
Forfeited	(339,655)	17.39
End of period	1,315,179[2]	10.21
December 31, 2009 total compensation cost related to nonvested time-based restricted stock awards not yet recognized	$ 5 million	
Weighted average period over which the nonvested time-based restricted stock is expected to be recognized	2 years	

(1) Based on the market price of our common stock on the vesting date, $2 million in fair value vested.

(2) We estimate that 225,001 of these will be forfeited.

	2008	2007
	(in millions, except per unit amounts)	
Fair value of time-based restricted stock that vested based on market price of our common stock on the vesting date	$ 6	$ 9
Weighted-average grant date fair value of time-based restricted stock granted	19.47	18.91

Time-Based Cash Awards. We grant time-based cash awards (cash units with each cash unit having an equivalent fair market value of one share of our common stock on the vesting date) to officers and key employees. In general, these awards vest, subject to the participant s continued employment, three years from the grant date. In June 2009, the Compensation Committee of our Board of Directors granted 817,030 time-based cash units to employees under our stock and incentive plans. These awards will vest in June 2012. Compensation expense is measured at fair value on each financial reporting measurement date, net of estimated forfeitures, and expensed on a straight-line basis (although subject to changes in fair value) over the requisite service period. As of December 31, 2009 and 2008, we had $1 million liability and $2 million liability, respectively, recorded for these awards.

During 2009, 2008 and 2007, 143,959, 218,524 and 392,126 time-based cash awards vested and were paid in the amount of $1 million, $4 million and $8 million, respectively. As of December 31, 2009, the total compensation cost related to nonvested time-based cash awards not yet recognized is $3 million and the weighted-average period over which it is expected to be recognized is two years.

Performance-Based and Market-Based Awards. We grant performance-based and market-based awards to officers and key employees. The number of performance-based awards earned is determined at the end of each performance period. As of December 31, 2009 and 2008, there were no outstanding performance-based awards. As of December 31, 2009 and 2008, there were 242,098 and 354,772 outstanding market-based awards, respectively. Compensation expense is measured at fair value, net of estimated forfeitures, at each reporting measurement date preceding the grant date for accounting purposes. As of December 31, 2009 and 2008, we had insignificant amounts recorded for these awards. As of December 31, 2009, no market-based awards had vested.

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RRI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized performance-based option activity of the 2004-2006 performance-based awards through the Key Employee Award Program is:

	2009			
	Options	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Term (Years)**	**Aggregate Intrinsic Value (in millions)**
Beginning of period	2,854,000	$ 8.34	5	$
Expired	(715,200)	8.94		
End of period	2,138,800	8.14	3	
Exercisable at end of period	2,138,800	8.14	3	
Weighted average grant date fair value	N/A			

Our option awards under the 2004-2006 Key Employee Award Program was based on the following weighted average assumptions and resulting fair values for 2008 and 2007:

Expected term in years(1)	3
Estimated volatility(2)	31.21%
Risk-free interest rate	4.9%
Dividend yield	0%
Weighted-average fair value	7.52

(1) The expected term is based on a projection of exercise behavior considering the contractual terms and the participants of the option awards.

(2) We estimated volatility based on historical and implied volatility of our common stock.

Other than the performance-based and market-based awards that vested in 2007, there were no other material performance-based or market-based awards that vested in 2009, 2008 and 2007.

Employee Stock Purchase Plan. Under the RRI Energy, Inc. Employee Stock Purchase Plan (ESPP), which was terminated effective December 31, 2009, substantially all employees could purchase our common stock through payroll deductions of up to 15% of eligible compensation during semiannual offering periods commencing on January 1 and July 1 of each year. The share price paid by participants equaled 85% of the lesser of the average market price on the first or last business day of each offering period.

The estimated fair value of the discounted share price element in our ESPP was based on the following weighted average assumptions:

	2009	**2008**	**2007**
Expected term in years	0.5	0.5	0.5
Estimated volatility[1]	131.35%	37.44%	21.32%
Risk-free interest rate	0.30%	2.94%	5.07%
Dividend yield	0%	0	