MIRANT CORP
Form 10-K
February 27, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-16107

Mirant Corporation

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**20-3538156** (I.R.S. Employer Identification No.)
1155 Perimeter Center West, Suite 100, **Atlanta, Georgia** (Address of Principal Executive Offices)	**30338** (Zip Code)

(678) 579 5000

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**New York Stock Exchange**
Series A Warrants	**New York Stock Exchange**
Series B Warrants	**New York Stock Exchange**

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

None

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

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

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

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 registrants 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. ¨

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

Large Accelerated Filer x	Accelerated Filer ¨
Non-accelerated Filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $6,974,396,638 on June 30, 2008 (based on $39.15 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day).

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. x Yes ¨ No

As of February 20, 2009, there were 144,127,672 shares of the registrant s Common Stock, $0.01 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement for the 2009 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K to the extent described herein.

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Glossary of Certain Defined Terms

APSA Asset Purchase and Sale Agreement dated June 7, 2000, between the Company and Pepco.

Bankruptcy Code United States Bankruptcy Code.

Bankruptcy Court United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.

Baseload Generating Units Units that satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously.

CAIR Clean Air Interstate Rule.

CAISO California Independent System Operator.

Cal PX California Power Exchange.

CAMR Clean Air Mercury Rule.

CCX Chicago Climate Exchange.

CERCLA Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980.

Clean Air Act Federal Clean Air Act.

Clean Water Act Federal Water Pollution Control Act.

CO2 Carbon dioxide.

Company Old Mirant prior to January 3, 2006, and New Mirant on or after January 3, 2006.

CPUC California Public Utilities Commission.

DWR California Department of Water Resources.

EBITDA Earnings before interest, taxes, depreciation and amortization.

EITF The Emerging Issues Task Force formed by the Financial Accounting Standards Board.

EITF 02-3 EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

EOB California Electricity Oversight Board.

EPA United States Environmental Protection Agency.

EPS Earnings per share.

ERISA Employee Retirement Income Security Act of 1974.

FASB Financial Accounting Standards Board.

FERC Federal Energy Regulatory Commission.

FIN FASB Interpretation.

FIN 39 FIN No. 39, *Offsetting of Amounts Related to Certain Contracts.*

FIN 45 FIN No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others An Interpretation of FASB Statements Nos. 5, 57, and 107 and Rescission of FASB Interpretation No. 34.*

FIN 46R FIN No. 46(R), *Consolidation of Variable Interest Entities (Revised December 2003) an Interpretation of Accounting Research Bulletin No. 51*.

FIN 47 FIN No. 47, *Accounting for Conditional Asset Retirements an interpretation of FASB Statement No. 143*.

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FIN 48 FIN No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*.

FSP FASB Staff Position.

FSP FAS 132R-1 FSP FAS No. 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets (Revised 2003)*.

FSP FAS 157-2 FSP FAS No. 157-2, *Effective Date of FASB Statement No. 157*.

FSP FAS 157-3 FSP FAS No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active.*

FSP FIN 39-1 FSP FIN No. 39-1, *Amendment of FASB Interpretation No. 39 (FIN 39).*

GAAP Generally accepted accounting principles in the United States.

Gross Margin Operating revenue less cost of fuel, electricity and other products, excluding depreciation and amortization.

Hudson Valley Gas Hudson Valley Gas Corporation.

IBEW International Brotherhood of Electrical Workers.

InterContinental Exchange InterContinental Exchange, Inc.

Intermediate Generating Units Units that meet system requirements that are greater than baseload and less than peaking.

ISO Independent System Operator.

ISO-NE Independent System Operator-New England.

kW Kilowatt.

LIBOR London InterBank Offered Rate.

LTSA Long-term service agreement.

MC Asset Recovery MC Asset Recovery, LLC.

MDE Maryland Department of the Environment.

Mirant Old Mirant prior to January 3, 2006, and New Mirant on or after January 3, 2006.

Mirant Americas Mirant Americas, Inc.

Mirant Americas Energy Marketing Mirant Americas Energy Marketing, LP.

Mirant Americas Generation Mirant Americas Generation, LLC.

Mirant Asia-Pacific Mirant Asia-Pacific Limited sold by the Company in the second quarter of 2007.

Mirant Bowline Mirant Bowline, LLC.

Mirant Canal Mirant Canal, LLC.

Mirant Chalk Point Mirant Chalk Point, LLC.

Mirant Delta Mirant Delta, LLC.

Mirant Energy Trading Mirant Energy Trading, LLC.

Mirant Kendall Mirant Kendall, LLC.

Mirant Lovett Mirant Lovett, LLC.

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Mirant MD Ash Management Mirant MD Ash Management, LLC.

Mirant Mid-Atlantic Mirant Mid-Atlantic, LLC and, except where the context indicates otherwise, its subsidiaries.

Mirant New York Mirant New York, LLC.

Mirant North America Mirant North America, LLC.

Mirant NY-Gen Mirant NY-Gen, LLC sold by the Company in the second quarter of 2007.

Mirant Pagbilao Mirant Pagbilao Corporation sold by the Company in the second quarter of 2007.

Mirant Potomac River Mirant Potomac River, LLC.

Mirant Potrero Mirant Potrero, LLC.

Mirant Power Purchase Mirant Power Purchase, LLC.

Mirant Services Mirant Services, LLC.

Mirant Sual Mirant Sual Corporation sold by the Company in the second quarter of 2007.

Mirant Trinidad Investments Mirant Trinidad Investments, LLC sold by the Company in the third quarter of 2007.

MW Megawatt.

MWh Megawatt hour.

NAAQS National ambient air quality standard.

NEPOOL New England Power Pool.

NERC North American Electric Reliability Council.

Net Capacity Factor The average production as a percentage of the potential net dependable capacity used over a year.

New Mirant Mirant Corporation on or after January 3, 2006.

NOL Net operating loss.

NOV Notice of violation.

NOx Nitrogen oxides.

NPCC Northeastern Power Coordinating Council.

NSR New source review.

NYISO Independent System Operator of New York.

NYMEX New York Mercantile Exchange.

NYSDEC New York State Department of Environmental Conservation.

NYSE New York Stock Exchange.

Old Mirant MC 2005, LLC, known as Mirant Corporation prior to January 3, 2006.

Orange and Rockland Orange and Rockland Utilities, Inc.

OTC Over-the-counter.

Ozone Season The period between May 1 and September 30 of each year.

Peaking Generating Units Units used to meet demand requirements during the periods of greatest or peak load on the system.

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Pepco Potomac Electric Power Company.

Petition Date July 14, 2003, the date Mirant and certain of its subsidiaries filed voluntary petitions for relief with the Bankruptcy Court.

PG&E Pacific Gas & Electric Company.

PJM PJM Interconnection, LLC.

Plan The plan of reorganization that was approved in conjunction with the Company s emergence from bankruptcy protection on January 3, 2006.

PPA Power purchase agreement.

PUHCA Public Utility Holding Company Act of 2005.

Reserve Margin Excess capacity over peak demand.

RFC ReliabilityFirst Corporation.

RGGI Regional Greenhouse Gas Initiative.

RMR Reliability-must-run.

RTO Regional Transmission Organization.

SAB SEC Staff Accounting Bulletin.

SAB 107 SAB No. 107, *Share-Based Payment.*

SAB 110 SAB No. 110, *Share-Based Payment an amendment of SAB No. 107.*

SEC U.S. Securities and Exchange Commission.

Securities Act Securities Act of 1933, as amended.

Series A Warrants Warrants issued on January 3, 2006, with an exercise price of $21.87 and expiration date of January 3, 2011.

Series B Warrants Warrants issued on January 3, 2006, with an exercise price of $20.54 and expiration date of January 3, 2011.

SFAS Statement of Financial Accounting Standards.

SFAS 5 SFAS No. 5, *Accounting for Contingencies*.

SFAS 107 SFAS No. 107, *Disclosure about Fair Value of Financial Instruments.*

SFAS 109 SFAS No. 109, *Accounting for Income Taxes*.

SFAS 123R SFAS No. 123(R), *Share-Based Payment (Revised 2004).*

SFAS 133 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (As Amended)*.

SFAS 141R SFAS No. 141(R), *Business Combinations (Revised 2007).*

SFAS 142 SFAS No. 142, *Goodwill and Other Intangible Assets.*

SFAS 143 SFAS No. 143, *Accounting for Asset Retirement Obligations*.

SFAS 144 SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

SFAS 157 SFAS No. 157, *Fair Value Measurements.*

SFAS 158 SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans: An Amendment of FASB Statements Nos. 87, 88, 106 and 132(R)*.

SFAS 159 SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*.

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SFAS 161 SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133*.

Shady Hills Shady Hills Power Company, L.L.C. sold by the Company in the second quarter of 2007.

SO2 Sulfur dioxide.

SOP 90-7 Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*.

UWUA Utility Workers Union of America.

VaR Value at risk.

VIE Variable interest entity.

Virginia DEQ Virginia Department of Environmental Quality.

WECC Western Electric Coordinating Council.

West Georgia West Georgia Generating Company, L.L.C. sold by the Company in the second quarter of 2007.

Wrightsville Wrightsville, Arkansas power generating facility sold by the Company in the third quarter of 2005.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements involve known and unknown risks and uncertainties and relate to future events, our future financial performance or our projected business results. In some cases, one can identify forward-looking statements by terminology such as may, will, should, expect, intend, seek, plan, think, anticipate predict, target, potential or continue or the negative of these terms or other comparable terminology.

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

- legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the industry of generating, transmitting and distributing electricity (the electricity industry); changes in state, federal and other regulations affecting the electricity industry (including rate and other regulations); changes in, or changes in the application of, environmental and other laws and regulations to which we and our subsidiaries and affiliates are or could become subject;
- failure of our plants to perform as expected, including outages for unscheduled maintenance or repair;
- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities in the energy markets and the extent and timing of the entry of additional competition in our markets;
- continued poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties and negative impacts on liquidity in the power and fuel markets in which we hedge and transact;
- increased credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected;
- our inability to access effectively the OTC and exchange-based commodity markets or changes in commodity market conditions and liquidity, which may affect our ability to engage in asset management, proprietary trading and fuel oil management activities as expected, or result in material gains or losses from open positions;
- deterioration in the financial condition of our counterparties and the failure of counterparties to pay amounts owed to us or to perform obligations or services due to us beyond collateral posted;
- hazards customary to the power generation industry and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;
- price mitigation strategies employed by ISOs or RTOs that reduce our revenue and may result in a failure to compensate our generating units adequately for all of their costs;
- changes in the rules used to calculate capacity, energy and ancillary services payments;

legal and political challenges to the rules used to calculate capacity, energy and ancillary services payments in the markets in which we operate;

volatility in our gross margin as a result of our accounting for derivative financial instruments used in our asset management, proprietary trading and fuel oil management activities and volatility in our cash flow from operations resulting from working capital requirements, including collateral, to support our asset management, proprietary trading and fuel oil management activities;

our ability to enter into intermediate and long-term contracts to sell power and to obtain adequate supply and delivery of fuel for our facilities, at our required specifications and on terms and prices acceptable to us;

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- the inability of our operating subsidiaries to generate sufficient cash flow to support our operations;
- our ability to borrow additional funds and access capital markets;
- strikes, union activity or labor unrest;
- weather and other natural phenomena, including hurricanes and earthquakes;
- the cost and availability of emissions allowances;
- curtailment of operations because of transmission constraints;
- environmental regulations that restrict our ability or render it uneconomic to operate our business, including regulations related to the emission of CO2 and other greenhouse gases;
- our inability to complete construction of emissions reduction equipment by January 2010 to meet the requirements of the Maryland Healthy Air Act, which may result in reduced unit operations and reduced cash flows and revenues from operations;
- our ability to execute our business plan in California, including entering into long-term power sales agreements for new generating facilities at our existing sites and entering into new tolling arrangements for our existing generating facilities;
- the ability of lenders under Mirant North America s revolving credit facility to perform their obligations;
- war, terrorist activities or the occurrence of a catastrophic loss;
- our consolidated indebtedness and the possibility that we or our subsidiaries may incur additional indebtedness in the future;
- restrictions on the ability of our subsidiaries to pay dividends, make distributions or otherwise transfer funds to us, including restrictions on Mirant North America contained in its financing agreements and restrictions on Mirant Mid-Atlantic contained in its leveraged lease documents, which may affect our ability to access the cash flows of those subsidiaries to make debt service and other payments; and
- the disposition of the pending litigation described in this Form 10-K.

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

Factors that Could Affect Future Performance

We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report.

In addition to the discussion of certain risks in Management s Discussion and Analysis of Results of Operations and Financial Condition and the accompanying Notes to Mirant s consolidated financial statements, other factors that could affect our future performance (business, financial condition or results of operations and cash flows) are set forth in Item 1A. Risk Factors.

Certain Terms

As used in this report, we, us, our, the Company and Mirant refer to Mirant Corporation and its subsidiaries, unless the context requires otherwise. Also, as used in this report we, us, our, the Company and Mirant refer to Old Mirant prior to January 3, 2006, and to New Mirant or after January 3, 2006.

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PART I

Item 1. *Business*

Overview

We are a competitive energy company that produces and sells electricity in the United States. We own or lease 10,112 MW of net electric generating capacity in the Mid-Atlantic and Northeast regions and in California. We also operate an integrated asset management and energy marketing organization based in Atlanta, Georgia. Our customers are principally ISOs, RTOs and investor-owned utilities. Our generating portfolio is diversified across fuel types, power markets and dispatch types and serves customers located near many major metropolitan load centers. Our total net generating capacity is approximately 30% baseload, 58% intermediate and 12% peaking.

Mirant Corporation was incorporated in Delaware on September 23, 2005. Pursuant to the Plan for Mirant and certain of its subsidiaries, on January 3, 2006, New Mirant emerged from bankruptcy and acquired substantially all of the assets of Old Mirant, a corporation that was formed in Delaware on April 3, 1993, and that had been named Mirant Corporation prior to January 3, 2006. The Plan provides that New Mirant has no successor liability for any unassumed obligations of Old Mirant. Old Mirant was then renamed and transferred to a trust, which is not affiliated with New Mirant.

We are focused on the operational performance of our generating facilities, generation of cash from operations and prudent growth of our business.

In 2008, we invested $672 million in our generating facilities. Much of this amount was invested in emissions control equipment to comply with the Maryland Healthy Air Act. We are installing flue gas desulphurization (FGD) emissions controls at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we have installed selective catalytic reduction systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk Point coal-fired unit. We are installing selective non-catalytic reduction systems at the three Dickerson coal-fired units. Including amounts already spent to date, we will invest $1.674 billion on emissions reduction controls. These controls will be capable of reducing emissions of SO_2, NO_x and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units.

Our investments in our generating facilities also reflect our targeted maintenance program to ensure consistent long-term availability of our generating facilities. Our equivalent forced outage rate was 8% in 2008 compared to 10% in 2007 for our Mid-Atlantic baseload coal-fired units excluding our Potomac River facility.

In 2008, we observed significant volatility in commodity prices. Our hedging program reduced our exposure to this volatility and contributed $207 million to our realized gross margin for 2008. In 2008, we generated $677 million of net cash provided by operating activities of our continuing operations.

As we generate excess cash from our operations, we will invest it in our business, but only when it is prudent to do so. Our existing generating facility sites have room to add an additional 7,500 MW to 10,000 MW of generating capacity and we continue to consider these opportunities.

We will return excess cash to our stockholders when we cannot prudently invest it in our business. In 2007, we sold our Philippine and Caribbean businesses, six U.S. natural gas-fired facilities and Mirant NY-Gen. After transaction costs and repayment of debt, the net proceeds to us from dispositions completed for the year ended December 31, 2007, were approximately $5.071 billion. Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion.

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The annual, quarterly and current reports, and any amendments to those reports, that we file with or furnish to the SEC are available free of charge on our website at www.mirant.com as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. General information about us, including our Corporate Governance Guidelines, the charters for our Audit, Compensation, and Nominating and Governance Committees, and our Code of Ethics and Business Conduct, can also be found at www.mirant.com. We will provide print copies of these documents to any stockholder upon written request to Corporate Secretary, Mirant Corporation, 1155 Perimeter Center West, Suite 100, Atlanta, Georgia 30338-5416. Information contained on our website is not incorporated into this Form 10-K.

Business Segments

We have four operating segments: Mid-Atlantic, Northeast, California and Other Operations. The Mid-Atlantic segment consists of four generating facilities located in Maryland and Virginia near Washington, D.C. The Northeast segment consists of three generating facilities located in Massachusetts and one generating facility located in New York near New York City. The California segment consists of three generating facilities located in or near San Francisco. Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances. For the years ended December 31, 2007 and 2006, Other Operations also included gains and losses related to a long-term PPA with Pepco (the Back-to-Back Agreement), which was terminated pursuant to a settlement agreement that became effective in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Back-to-Back Agreement.

The table below presents our capacity by region and our Net Capacity Factor for the year ended December 31, 2008:

Region	Total Capacity (MW)	Net Capacity Factor
Mid-Atlantic	5,230	33%
Northeast	2,535	13%
California	2,347	4%

The table below summarizes selected financial information of our continuing operations by business segment for the year ended December 31, 2008 (dollars in millions):

Business Segment	Revenues	%	Gross Margin	%	Operating Income/ (Loss)	%
Mid-Atlantic	$ 2,279	72%	$ 1,714	81%	$ 1,218	91%
Northeast	617	19%	179	8%	23	2%
California	186	6%	127	6%	35	2%
Other Operations	102	3%	103	5%	67	5%
Eliminations	4	%	6	%	(2)	%
Total	$ 3,188	100%	$ 2,129	100%	$ 1,341	100%

Eliminations are primarily related to intercompany sales of emissions allowances. For selected financial information about our business segments, see Note 14 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our generating facilities.

Asset Management

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, managing fuel and providing logistical support for

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the operation of our facilities (for example, by procuring transportation for coal). We typically sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (the spot price). Spot prices for electricity are volatile, as are prices for fuel and emissions allowances, and in order to reduce the risk of that volatility and achieve more predictable financial results, it is our strategy to enter into hedges forward sales of electricity and forward purchases of fuel and emissions allowances to permit us to produce and sell the electricity for various time periods. In addition, given the high correlation between natural gas prices and electricity prices in the markets in which we operate, we enter into forward sales of natural gas to hedge our exposure to changes in the price of electricity. We procure our hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options. We also sell capacity and ancillary services where there are markets for such products and when it is economic to do so.

We use dispatch models to assist us in making daily decisions regarding the quantity and price of the power our facilities will generate and sell into the markets. We bid the energy from our generating facilities into the day-ahead energy market and sell ancillary services through the ISO and RTO markets. We sell capacity either bilaterally or through auction processes in each ISO and RTO in which we participate. We work with the ISOs and RTOs in real time to ensure that our generating facilities are dispatched economically to meet the reliability needs of the market.

At February 10, 2009, our aggregate hedge levels based on expected generation for each period were as follows:

	Aggregate Hedge Levels Based on Expected Generation				
	2009	**2010**	**2011**	**2012**	**2013**
Power	96%	62%	22%	24%	24%
Fuel	90%	64%	53%	29%	6%

Power

We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our Northeast gas and oil-fired generation through OTC transactions. However, we generally do not hedge our intermediate and peaking units for tenors greater than 12 months. A significant portion of our hedges are financial swap transactions between Mirant Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. We also enter into forward sales of natural gas to hedge our exposure to changes in the price of electricity.

While OTC transactions make up a substantial portion of our economic hedge portfolio, at times we sell non-standard, structured products to customers. Additionally, our California facilities operate under contracted capacity and RMR contracts.

Fuel

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013. For our oil-fired units, we typically purchase fuel from a limited number of suppliers under contracts with terms of varying lengths.

Our coal supply comes primarily from the Central Appalachian and Northern Appalachian coal regions. Most of our coal is delivered by rail, except for a portion of our coal deliveries at our Morgantown station, which is received by barge at our unloading facility that became operational in the third quarter of 2008. The barge

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unloader enables us to receive coal from international locations as well. We monitor coal supply and delivery logistics carefully and, despite occasional interruptions of scheduled deliveries, to date we have managed to avoid any significant detrimental effects on our operations. We typically maintain a target level of coal inventory at our coal-fired facilities for this purpose. Interruptions of scheduled deliveries can result from a variety of disruptions, including coal supplier operational issues, rail system disruptions or severe weather.

Emissions

Our commercial operations manage the acquisition and use of emissions allowances for our generating facilities. Primarily as a result of the pollution control equipment we are installing to comply with the requirements of the Maryland Healthy Air Act, we have significant excess SO2 and NOx emissions allowances for future periods. We plan to continue to maintain some SO2 and NOx emissions allowances in excess of what we need to support our expected generation in case our actual generation exceeds our current forecasts for future periods and for possible future additions of generating capacity. During the fourth quarter of 2007, we began a program to sell excess SO2 and NOx emissions allowances under certain market conditions. At December 31, 2008, the estimated fair value of our excess SO2 and NOx emissions allowances exceeded the carrying value recorded on our consolidated balance sheet by approximately $63 million.

In September 2008, we joined the CCX, which is a voluntary greenhouse gas registry, reduction and trading system. As part of the agreement for membership in CCX, we have committed to meet annual emissions reduction targets and, by 2010 to reduce our greenhouse gas emissions by six percent below the average of our 1998 to 2001 levels. We expect to satisfy our reduction targets primarily through previously implemented generating unit retirements and capacity factor reductions.

Mid-Atlantic Region

We own or lease four generating facilities in the Mid-Atlantic region with total net generating capacity of 5,230 MW. Our Mid-Atlantic region had a combined 2008 Net Capacity Factor of 33%.

The following table presents the details of our Mid-Atlantic generating facilities:

Facility	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region
Chalk Point	2,413	Natural Gas/Coal/Oil	Intermediate/ Baseload/Peaking	Maryland	RFC
Dickerson	849	Natural Gas/Coal/Oil	Baseload/Peaking	Maryland	RFC
Morgantown	1,486	Coal/Oil	Baseload/Peaking	Maryland	RFC
Potomac River	482	Coal	Baseload/ Intermediate	Virginia	RFC
Total Mid-Atlantic	5,230				

The Chalk Point facility is our largest generating facility. It consists of two coal-fired baseload units, two dual-fueled (oil and gas) intermediate units and two oil-fired and five dual-fueled (oil and gas) peaking units. Our next largest facility is the Morgantown facility. It consists of two coal-fired baseload units and six oil-fired peaking units. The Dickerson facility has three coal-fired baseload units, and one oil-fired and two dual-fueled (oil and gas) peaking units. The Potomac River facility has three coal-fired baseload units and two coal-fired intermediate units.

In July 2008, the City of Alexandria, Virginia (in which the Potomac River generating facility is located) and Mirant Potomac River entered into an agreement containing certain terms that were included in a proposed

comprehensive state operating permit for the Potomac River generating facility issued by the Virginia DEQ that month. Under that agreement, Mirant Potomac River committed to spend $34 million over several years to reduce particulate emissions. The $34 million was placed in escrow and is included in funds on deposit and other noncurrent assets in the accompanying consolidated balance sheets and in our estimated capital expenditures presented in Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition Overview . See Note 17 to our consolidated financial statements contained elsewhere in this report for a more detailed discussion on the Potomac River Settlement.

Prior to the issuance of the comprehensive state operating permit in July 2008, the Potomac River generating facility operated under a state operating permit issued June 1, 2007, that significantly restricted the facility s operations by imposing stringent limits on its SO2 emissions and constraining unit operations so that no more than three of the facility s five units could operate at one time. In compliance with the comprehensive permit, in 2008 we merged the stacks for units 3, 4 and 5 into one stack at the Potomac River generating facility and, in January 2009, we merged the stacks for units 1 and 2 into one stack. With the completion of the stack combinations, the permit issued in July 2008 will not constrain operations of the Potomac River generating facility below historical operations and will allow operation of all five units at one time. Certain provisions of Virginia s air emissions regulations adopted to implement the CAIR, however, could constrain the facility s operations, as described below in *Environmental Regulation-Virginia CAIR Implementation* .

Northeast Region

We own generating facilities in the Northeast region with total net generating capacity of 2,535 MW. Our Northeast region had a combined 2008 Net Capacity Factor of 13%. The Northeast region is comprised of our facilities located in Massachusetts and New York. Generation is sold from our Northeast facilities through a combination of bilateral contracts, spot market transactions and structured transactions.

The following table presents the details of our facilities in the Northeast Region:

Facility	**Total Net Generating Capacity (MW)**	**Primary Fuel Type**	**Dispatch Type**	**Location**	**NERC Region**
Bowline	1,139	Natural Gas/Oil	Intermediate/ Peaking	New York	NPCC
Canal	1,126	Natural Gas/Oil	Intermediate	Massachusetts	NPCC
Kendall	256	Natural Gas/Oil	Baseload/Peaking	Massachusetts	NPCC
Martha s Vineyard	14	Diesel	Peaking	Massachusetts	NPCC
Total Northeast Region	2,535				

The Bowline facility is a dual-fueled (natural gas and oil) facility comprised of two intermediate/peaking units. The capacity, energy and ancillary services from our Bowline generating facility are sold into the bilateral markets and into the markets administered by the NYISO. For a discussion of the NYISO, see *Regulatory Environment* below.

The Canal facility consists of one oil-fired intermediate unit and one dual-fueled (oil and gas) intermediate unit. The Kendall facility consists of one combined cycle dual-fueled (oil and gas) baseload unit, two 1,300 pound steam boilers and one simple cycle jet engine peaking unit. The Martha s Vineyard facility consists of five diesel peaking units. The capacity, energy and ancillary services from our Massachusetts generating units are sold into the NEPOOL bilateral markets and into the markets administered by the ISO-NE. For a discussion of the NEPOOL and the ISO-NE, see *Regulatory Environment* below. The Kendall facility also has long-term agreements under which it sells steam resulting from electricity production or is reimbursed for production costs when called upon to provide steam under the agreements.

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The Canal facility is located in the lower Southeastern Massachusetts (SEMA) area in ISO-NE. ISO-NE has previously determined that, at times, it is necessary for the Canal facility to operate to meet local reliability criteria for SEMA when it was not economic for the Canal facility to operate based upon prevailing market prices. When the Canal facility operates to meet local reliability criteria, we are compensated at the price we bid into the ISO-NE rather than at the lower market price.

ISO-NE and NSTAR recently developed a plan to upgrade the SEMA transmission system that will reduce the local reliability need for the Canal facility. These transmission upgrades are scheduled for completion in September 2009. Once these upgrades are completed, we expect that the need for the Canal facility to operate for reliability will be reduced. As such, the gross margin from our Canal facility may decrease significantly compared to that generating facility s gross margin for recent years.

On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into a consent decree (the 2003 Consent Decree) governing the future of the Lovett facility s two coal-fired units (units 4 and 5). Pursuant to the 2003 Consent Decree as amended on May 10, 2007, we discontinued operation of unit 4 as of May 7, 2007, and unit 5 on April 19, 2008. In addition, we discontinued operation as of May 7, 2007, of unit 3, a dual-fueled unit (natural gas and oil), the only other operating unit at the facility because it was uneconomic to run the unit. We have substantially completed the demolition of the Lovett facility.

California

We own three generating facilities in California with total net generating capacity of 2,347 MW. Our California facilities had a combined 2008 Net Capacity Factor of 4%. The following table presents the details of our California facilities:

Facility	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region
Contra Costa	674	Natural Gas	Intermediate	California	WECC
Pittsburg	1,311	Natural Gas	Intermediate	California	WECC
Potrero	362	Natural Gas/Diesel	Intermediate/ Peaking	California	WECC
Total California	2,347				

The Contra Costa and Pittsburg facilities are located in Contra Costa County and the Potrero facility is located in the City of San Francisco. The Contra Costa facility consists of two gas-fired intermediate units and the Pittsburg facility consists of three gas-fired intermediate units. The Potrero facility consists of one gas-fired intermediate unit and three diesel peaking units. Through the end of 2006, the majority of our California units were subject to RMR arrangements with the CAISO. These agreements are described further under *Regulatory Environment* below. Pittsburg unit 7 and Contra Costa unit 6 were not subject to an RMR arrangement, and thus functioned solely as merchant facilities in the CAISO. In 2006, we either sold the output of Pittsburg unit 7 and Contra Costa unit 6 into the market through bilateral transactions with utilities and other merchant generators, or dispatched the units in the CAISO clearing markets.

On July 28, 2006, we signed two tolling agreements with PG&E to provide electricity from all our natural gas-fired units in service at Contra Costa and Pittsburg, including Contra Costa unit 6 and Pittsburg unit 7. The agreements are for 100% of the capacity from these units. The contracts have varying tenors for each unit covering from one to five years, and include capacity of 1,985 MW for 2008 and 2009, 1,303 MW for 2010 and 674 MW for 2011. We receive monthly capacity payments with bonuses and/or penalties based on guaranteed heat rate and availability tolerances. As a result of these contracts, the Contra Costa and Pittsburg units are no longer subject to the RMR agreements.

All of our Potrero units continue to be subject to RMR arrangements through 2009 and annually thereafter based upon the CAISO s local reliability requirements.

Our generating facilities in California depend almost entirely on payments they receive to operate in support of system reliability. The energy, capacity and ancillary services markets, as currently constituted, will not support the capital expenditures necessary to repower or reconstruct our facilities to make them commercially viable in a merchant market. In order to obtain the necessary capital support for repowering or reconstructing our facilities, we will need to obtain a contract with a creditworthy buyer. Absent that, our generating facilities in California will be commercially viable only as long as they are necessary for reliability.

Other Operations

In addition to selling the electricity we produce and buying the fuel and emissions allowances we need to produce electricity (asset management), we buy and sell some electricity, fuel and emissions allowances as part of our proprietary trading and fuel oil management activities.

We engage in proprietary trading to gain information about the markets to support our asset management and to take advantage of selected opportunities that we identify from time to time. We enter into fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories and to optimize the approximately three and one half million barrels of storage capacity that we own or lease.

Proprietary trading and fuel oil management activities together typically comprise less than 10% of our realized gross margin. All of our commercial activities are governed by a comprehensive Risk Management Policy, which includes limits on the size of positions and VaR for our proprietary trading and fuel oil management activities. For 2008, our average daily VaR for these activities was approximately $2 million.

Competitive Environment

The power generating industry is capital intensive and highly competitive. Our competitors include regulated utilities, merchant energy companies, financial institutions and other companies, including companies owned by hedge funds and private equity funds. For a discussion of competitive factors and the effects of seasonality on our business see Item 1A. Risk Factors . Coal-fired generation, natural gas-fired generation and nuclear generation currently account for approximately 48%, 22% and 19%, respectively, of the electricity produced in the United States. Hydroelectric and other energy sources account for the remaining 11% of electricity produced.

The recent economic downturn and programs to reduce the demand for electricity have resulted in a decrease in the rate at which the long-term demand for electricity is forecasted to grow. Given the substantial time necessary to permit and construct new power plants, the process to add generating capacity must begin years in advance of anticipated growth in demand. A number of ISOs and RTOs, including those in markets in which we operate, have implemented capacity markets as a way to encourage construction of additional generation, but it is not clear whether and when independent power producers will be sufficiently incented to build this required new generation. The costs to construct new generation facilities have been rising and there is substantial environmental opposition to building either coal-fired or nuclear plants.

There are several proposed upgrades to the transmission systems in the markets in which we operate that could mitigate the need for additional generating capacity. To the extent that these upgrades are completed, prices for electricity and capacity could be lower than they might otherwise be.

The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in 2007. Global demand for coal to generate electricity has been a significant factor influencing domestic prices for the types of coal that we use. At the same time, the prices for power and natural

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gas were extremely volatile, increasing during the first half of 2008 and decreasing during the second half of 2008. Fluctuations in natural gas prices have a significant effect on the price of power, especially in the PJM market where the marginal price for power is often set by gas-fired units. In 2008 as compared to 2007, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period.

Climate change concerns have led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions, including CO2. The costs of compliance with such efforts could affect our ability to compete in the markets in which we operate, especially with our coal-fired generating facilities.

Regulatory Environment

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

The FERC has authorized our subsidiaries that constitute public utilities under the Federal Power Act to sell wholesale energy, capacity and certain ancillary services at market-based rates. The majority of the output of the generating facilities owned by our subsidiaries is sold pursuant to this market-based rate authorization, although certain of our facilities sell their output under cost-based RMR agreements for which separate rate authorization was granted by the FERC, as explained below. The FERC could revoke or limit our market-based rate authority if it determined that we possess insufficiently mitigated market power in a regional electricity market. Under the Natural Gas Act, our subsidiary that sells natural gas for resale is deemed by the FERC to have blanket certificate authority to undertake these sales at market-based rates.

The FERC requires that our public utility subsidiaries with market-based rate authority and our subsidiary with blanket certificate authority adhere to general rules against market manipulation as well as certain market behavior rules and codes of conduct. If any of our subsidiaries were found to have engaged in market manipulation, the FERC has the authority to impose a civil penalty of up to $1 million per day per violation. In addition to the civil penalties, if any of our subsidiaries were to engage in market manipulation or violate the market behavior rules or codes of conduct, the FERC could require a disgorgement of profits or revoke the subsidiary s market-based rate authority or blanket certificate authority. If the FERC were to revoke market-based rate authority, our affected public utility subsidiary would have to file a cost-based rate schedule for all or some of its sales of electricity at wholesale.

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

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

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

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

Load-serving entities within PJM are required to have adequate sources of generating capacity. Our facilities located in the Mid-Atlantic region that sell electricity into the PJM market participate in the reliability pricing model (the RPM) forward capacity market. The PJM RPM capacity auctions are designed to provide forward prices for capacity that are intended to ensure that adequate resources are in place to meet the region s demand requirements. PJM has conducted five PJM RPM capacity auctions and we began receiving payments in June 2007 as a result of the first auction. The FERC s orders approving and implementing the PJM RPM capacity auctions have been appealed to the United States Court of Appeals for the District of Columbia Circuit (the DC Circuit). We cannot predict what, if any, effect the appeal process will have on the RPM forward capacity market and the capacity payments that we have received or expect to receive from that market.

The results of the PJM RPM capacity auctions for the delivery area where our facilities are located were as follows:

Auction Date	Capacity Period	Resource Clearing Price per MW-day	
April 2007	June 1, 2007 to May 31, 2008	$	188.54
July 2007	June 1, 2008 to May 31, 2009	$	210.11
October 2007	June 1, 2009 to May 31, 2010	$	237.33
January 2008	June 1, 2010 to May 31, 2011	$	174.29
May 2008	June 1, 2011 to May 31, 2012	$	110.00

Since 2008, annual auctions have been conducted to procure capacity three years prior to each delivery period. The first annual auction took place in May 2008, for the provision of capacity from June 1, 2011 to May 31, 2012.

On December 12, 2008, PJM filed with the FERC to revise elements of the RPM forward capacity market. PJM intends to implement these changes in time for the May 2009 annual auction for the provision of capacity from June 1, 2012 to May 31, 2013. We filed an opposition to the proposed changes with the FERC. On February 9, 2009, PJM and a coalition of PJM customers (the PJM Load Group) as well as several state commissions filed a settlement agreement with the FERC that would materially modify several provisions of the December 12, 2008, filing to the detriment of suppliers in the RPM capacity auction. Under the FERC s rules and regulations, any party to a contested proceeding may unilaterally file a settlement in that proceeding with the FERC. We filed comments opposing the settlement. At this time, we do not know if the FERC will accept, reject or modify PJM s proposed changes to the RPM forward capacity market submitted in both the December 12, 2008, filing and February 9, 2009, settlement filing. Therefore, we cannot predict what effect, if any, these changes will have on the May 2009 PJM RPM auction.

Northeast Region. Our Bowline facility participates in a market controlled by the NYISO. The NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, the NYISO calculates energy prices using a locational marginal pricing model. The NYISO also administers a spot market for energy, as well as markets for installed capacity and services that are ancillary to transmission service, such as operating reserves and regulation service (which balances resources with load). The NYISO s locational capacity market rules use a demand curve mechanism to determine for every month the required amount of installed capacity as well as installed capacity prices to be paid for three locational zones: New York City, Long Island and Rest of State. Our facility operates in the Rest of State locational zone.

Our Canal, Kendall and Martha s Vineyard facilities participate in a market administered by ISO-NE. Mirant Energy Trading is a member of NEPOOL, which is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and which functions as an advisory organization to ISO-NE. The FERC approved ISO-NE as the RTO for the New England region making ISO-NE responsible for market rule filings at the FERC, in addition to its responsibilities for the operation of transmission systems and for the administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model similar to the model used in PJM and NYISO.

On March 6, 2006, a settlement proposal was filed with the FERC among ISO-NE and multiple market participants for a forward capacity market (the FCM) under which annual capacity auctions would be conducted for supply three years in advance of provision. The settlement provided for a four-year transition period during which capacity suppliers receive a set price for their capacity commencing on December 1, 2006, with price escalators through May 31, 2010. Beginning December 1, 2006, our generating facilities began receiving capacity revenues under the FCM transition period. During the FCM transition period we received or will receive capacity revenues between $3.05 per kW- month and $4.10 per kW-month. The first auction took place in February 2008 for the period June 1, 2010 to May 31, 2011. The clearing price was $4.50 per kW-month, which was the price floor established as part of the FCM settlement. Our generating facilities will receive $4.25 per kW-month based on our pro-rata amount of the generating capacity that was sold in the auction. The next auction was held in December 2008 for the period June 1, 2011 to May 31, 2012, and the clearing price was $3.60 per kW-month. Our generating facilities will receive $3.12 per kW-month based on our pro-rata amount of the generating capacity that was sold in the auction. In March 2008, the FERC s orders approving and implementing the FCM were affirmed by the DC Circuit; however, the DC Circuit reversed a portion of the FERC s orders regarding the rights of a non-settling party to challenge the FCM charges through future proceedings initiated at the FERC. On January 15, 2009, the FERC issued an order on remand, directing the settling parties to revise the applicable standard of review to be consistent with the DC Circuit s decision. We do not expect that the DC Circuit s reversal of this element of the FCM or the FERC s actions on remand will have an effect on the FCM and the capacity payments we receive under the FCM.

California. Our California facilities are located inside the CAISO s control area. The CAISO schedules transmission transactions, arranges for necessary ancillary services and administers a real-time balancing energy market. Most sales in California are pursuant to bilateral contracts, but a significant percentage of electrical energy is sold in the real-time market. The CAISO does not operate a forward market like those described for PJM and other eastern markets, nor does it currently operate a capacity market.

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The CAISO has proposed changes to its market design to mirror more closely the eastern markets, but not including a capacity market. Although the CAISO has delayed the market redesign several times, it now expects to fully implement it in 2009. The CPUC has begun a proceeding to develop, together with the CAISO, a wholesale capacity market. FERC approval would be required for any such capacity market to become effective. We cannot at this time predict the outcome of the CPUC proceeding or the timing or structure of a wholesale capacity market in California.

Mirant Potrero is party to a PPA with PG&E that from 2006 through 2012 allows PG&E to dispatch and purchase the output of our Potrero units that have been designated RMR units which for 2009 includes all of the Potrero units. Under the PPA, through 2008, PG&E paid us charges equivalent to the rates we charged during 2004 when the units were designated as RMR units reduced by $1.4 million for each year since 2004. For 2009 through 2012, the charges for the units that are then subject to the PPA will be determined annually by the FERC pursuant to the cost-based formula rates set forth in the RMR agreement. On December 4, 2008, the FERC issued an order approving the charges for the Potrero units for 2009 and 2010. The approved PPA charges for 2009 and 2010 are expected to result in approximately the same level of gross margin for Mirant Potrero as it recognized for 2008.

Environmental Regulation

Our business is subject to extensive environmental regulation by federal, state and local authorities. We must comply with applicable laws and regulations, and obtain and comply with the terms of government issued permits. Our costs of complying with environmental laws, regulations and permits are substantial, including significant environmental capital expenditures. See Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition Capital Expenditures and Capital Resources for additional information.

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures.

Air Emissions Regulations

Our most significant environmental requirements generally fall under the Clean Air Act, regional initiatives and similar state laws. Under the Clean Air Act, we are required to comply with a broad range of mandates concerning air emissions, operating practices and pollution control equipment. Most of our facilities are located in or near metropolitan areas, including New York City, Boston, San Francisco and Washington D.C., which are classified by the EPA as not achieving certain NAAQS (non-attainment areas). As a result of the classification of each of these areas as a non-attainment area, our operations are subject to more stringent air pollution requirements than those applicable to plants located elsewhere. Various states where we have facilities also have other air quality laws and regulations with increasingly stringent limitations and requirements that will affect us in future years. In the future, we expect increased regulation of our air emissions. Significant air regulatory programs to which we are subject are described below.

Clean Air Interstate Rule (CAIR). In 2005, the EPA promulgated the CAIR, which established in the eastern United States SO2 and NOx cap-and-allowance trading programs applicable directly to states and indirectly to generating facilities. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NOx and 2010 for SO2 and more stringent caps going into effect in 2015. Various parties appealed the EPA s adoption of the CAIR, and on July 11, 2008, the DC Circuit in *State of North Carolina v. Environmental Protection Agency* issued an opinion that would have vacated the CAIR. Various parties filed requests for rehearing with the DC Circuit and on December 23, 2008, the DC Circuit issued a second opinion in which it granted rehearing only to the extent that it remanded the case to the EPA without vacating the CAIR. Accordingly, the CAIR will remain effective until it is replaced by a rule consistent with the DC Circuit s opinions.

Maryland Healthy Air Act. The Maryland Healthy Air Act was enacted in April 2006 and requires reductions in SO2, NOx and mercury emissions from large coal-fired power facilities. The state law also requires

Maryland to join the RGGI, which is discussed below. The Maryland Healthy Air Act prohibits power facilities from purchasing emissions allowances instead of installing emissions control equipment. We are installing FGD emissions controls at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we have installed selective catalytic reduction systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk Point coal-fired unit. We are installing selective non-catalytic reduction systems at the three Dickerson coal-fired units. These controls will be capable of reducing emissions of SO2, NOx and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units.

The Maryland Healthy Air Act imposes mass limits for (i) emissions of NOx in 2009 with further reductions in 2012 (including sublimits during the Ozone Season) and (ii) emissions of SO2 in 2010 with further reductions in 2013. The Maryland Healthy Air Act also imposes restrictions on emissions of mercury beginning in 2010 with further reductions in 2013. The control equipment we have installed or are installing to meet Maryland state standards will allow our Maryland facilities to comply with (a) all of the requirements of the Maryland Healthy Air Act and (b) the first phase of the CAIR without having to purchase emissions allowances.

Including amounts already spent to date, we expect to incur total capital expenditures of $1.674 billion to comply with the requirements for SO2, NOx and mercury emissions under the Maryland Healthy Air Act. On July 30, 2007, our subsidiaries Mirant Mid-Atlantic and Mirant Chalk Point entered into an agreement with Stone & Webster, Inc. for engineering, procurement and construction services relating to the installation of the FGD systems described above. The expected cost under the agreement is approximately $1.13 billion and is a part of the $1.674 billion of capital expenditures that we expect to incur to comply with the Maryland Healthy Air Act. We will have planned outages in 2009 to complete the installation of the FGD control systems. During those outages, we also will perform routine maintenance activities. As of December 31, 2008, we have paid approximately $997 million of the $1.674 billion for capital expenditures related to the Maryland Healthy Air Act. For the year ended December 31, 2008, we paid $683 million for capital expenditures, excluding capitalized interest, of which $497 million related to the Maryland Healthy Air Act. We expect that available cash and future cash flows from operations will be sufficient to fund the remaining capital expenditures.

Clean Air Mercury Rule (CAMR). In 2005, the EPA issued the CAMR, which would have limited total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. In February 2008, the DC Circuit vacated the CAMR and the EPA s decision to delist coal- and oil-fired electric utility steam generating units from sources regulated under section 112 of the Clean Air Act. The EPA and the Utility Air Regulatory Group sought review of the DC Circuit s decision by the United States Supreme Court. In February 2009, the EPA filed to withdraw its petition for review, stating that it intends to promulgate alternative regulations to address mercury emissions, and the United States Supreme Court subsequently denied the petition for review. As a result of the DC Circuit decision, mercury emissions from coal- and oil-fired generating facilities are now subject to Section 112 of the Clean Air Act, which authorizes the EPA to develop standards for the installation of maximum achievable control technology (MACT) to reduce emissions of Hazardous Air Pollutants, including mercury. While the EPA has the authority to develop MACT standards for mercury, it has not yet promulgated such standards. We expect many of our coal-fired facilities to emit less mercury as a result of the SO2 and NOx controls that have been, or soon will be, installed.

NSR Enforcement Initiative. In 2001, the EPA requested information concerning some of our facilities in Maryland and Virginia covering a time period that pre-dates our acquisition or lease of those facilities in December 2000. We responded fully to this request. Under the APSA, Pepco is responsible for fines and penalties arising from any violation associated with operations prior to our subsidiaries acquisition or lease of the facilities. If a violation is determined to have occurred at any of the facilities, our subsidiary owning or leasing the facilities may be responsible for the cost of purchasing and installing emissions control equipment, the cost of which may be material. Our subsidiaries owning or leasing the Chalk Point, Dickerson and Morgantown facilities in Maryland are installing a variety of emissions control equipment at those facilities to comply with the Maryland Healthy Air Act, but that equipment may not include all of the pollution control equipment that could be required if a violation of the EPA s NSR regulations is determined to have occurred at one or more of those facilities. If such a violation is determined to have occurred after our subsidiaries acquired or leased the facilities or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the facility at issue could also be subject to fines and penalties by the state or federal government for the period after its acquisition or lease of the facility, the cost of which may be material, although applicable bankruptcy law may bar such liability for periods prior to January 3, 2006, when the Plan became effective for us and our subsidiaries that own or lease these facilities.

Massachusetts CAIR Implementation. The Commonwealth of Massachusetts Department of Environmental Protection (MADEP) promulgated regulations to take effect in 2009 to reduce NOx emissions from certain generating facilities. The Massachusetts regulations will require our Canal and Kendall generating facilities during the Ozone Season to reduce their emissions of NOx or utilize emissions allowances in amounts greater than they utilized prior to 2009.

New York CAIR Implementation. The NYSDEC promulgated regulations implementing the SO2 and NOx emissions reductions required by the federal CAIR beginning in 2009. Those regulations will limit NOx emissions through both an annual cap-and-trade program and through a seasonal cap-and-trade program during the Ozone Season, which will require our Bowline generating facility to reduce its emissions of NOx by running less or increasing its utilization of emissions allowances. The regulations also provide for an SO2 emissions program beginning in 2010 that will mandate increased utilization of federal SO2 allowances for every ton of SO2 emitted.

Virginia CAIR Implementation. In April 2006, Virginia enacted legislation that, among other things, granted the Virginia State Air Pollution Control Board the discretion to prohibit electric generating facilities located in a non-attainment area from purchasing SO2 and NOx allowances to achieve compliance under the CAIR. In the fourth quarter of 2007, the Virginia State Air Pollution Control Board approved regulations that it interprets as prohibiting the trading of SO2 and NOx allowances by facilities in non-attainment areas to satisfy the requirements of the CAIR as implemented by Virginia. Our Potomac River facility is located in a non-attainment area for ozone. Thus, this Virginia regulation effectively caps our SO2 and NOx emissions at amounts equal to the allowances allocated to the facility. Mirant Potomac River has appealed these regulations in Virginia state court. In July 2008, the Virginia state court issued a ruling dismissing our appeal, which ruling we have appealed. We have also petitioned (a) the EPA to reconsider and (b) the United States Court of Appeals for the Fourth Circuit (the Fourth Circuit) to review the EPA s final rule approving Virginia s CAIR program.

New York Consent Decree. In 2000, the State of New York issued an NOV to the previous owner of our Lovett facility alleging NSR violations associated with the operation of that facility prior to its acquisition by us. To resolve the issues raised by the State of New York, on June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into the 2003 Consent Decree. Under the 2003 Consent Decree, Mirant Lovett had three options: (1) install emissions controls on Lovett s two coal-fired units (units 4 and 5); (2) shut down unit 4 and convert unit 5 to natural gas; or (3) shut down unit 4 in 2008 and unit 5 in 2007. We concluded that the installation of the required emissions controls was uneconomic. We also concluded that operating unit 5 on natural gas was uneconomic.

On May 10, 2007, Mirant Lovett entered into an amendment to the 2003 Consent Decree with the State of New York that switched the deadlines for shutting down units 4 and 5 so that the deadline for compliance by unit 5 was extended until April 30, 2008, and the deadline for unit 4 was shortened. We discontinued operation of unit 4 as of May 7, 2007. In addition, we discontinued operation of unit 3 because it was uneconomic to run the unit. We shut down unit 5 on April 19, 2008, and have substantially completed the demolition of the Lovett facility.

State Regulation of Greenhouse Gases, including the RGGI. Concern over climate change has led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions. One such effort is the RGGI, a multi-state initiative in the Northeast outlining a cap-and-trade program to reduce CO2 emissions from units of 25 MW or greater. The RGGI program calls for signatory states to stabilize CO2 emissions to current levels from 2009 to 2015, followed by a 2.5% reduction each year from 2015 to 2018. Regulations to implement the RGGI have now been approved in each of Maryland, Massachusetts and New York.

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In 2009, we expect to produce approximately 16.6 million tons of CO_2 at our Maryland, Massachusetts and New York generating facilities. The RGGI regulations require those facilities to obtain allowances to emit CO_2 beginning in 2009. No allowances were granted to existing sources of such emissions. Instead, allowances have been made available for such facilities only by purchase through periodic auctions conducted quarterly or through subsequent purchase from a party that holds allowances sold through a quarterly auction process. The Maryland regulations implementing the RGGI also provide that if the allowance clearing price exceeds $7 (adjusted by changes in the consumer price index since 2005) per ton of CO_2 in the auctions of allowances that occur during the first three years, Maryland will withhold the remainder of that year s allowances from sale in any future auction during that calendar year and make those allowances available by direct sale to generators in Maryland. In this scenario, between zero and 50% of Maryland s allowances allocated for sale in that year may be made available for purchase by such generators. Any such allowances made available for each generator to purchase at $7 per ton, as adjusted, will be in proportion to each generator s annual average heat input during the period 2003 through 2005 as compared to the total average input for all affected Maryland generators in existence at that time.

The first auction of allowances by the RGGI states was held on September 25, 2008. The clearing price for the approximately 12.5 million allowances sold in the auction was $3.07 per ton. The second auction took place in December 2008, and the clearing price for the approximately 31.5 million allowances sold was $3.38 per ton. The allowances sold in these auctions can be used for compliance in any of the RGGI states. Further auctions will occur on a quarterly basis through 2011.

We are continuing to evaluate our options to comply with the RGGI, but its implementation in Maryland, Massachusetts and New York could have a material adverse effect upon our operations and our operating costs, depending upon the availability and cost of emissions allowances and the extent to which such costs may be offset by higher market prices to recover increases in operating costs caused by the RGGI.

In California, emissions of greenhouse gases are governed by the Global Warming Solutions Act (AB 32), which requires that greenhouse gas emissions be reduced to 1990 levels by 2020. AB 32 also requires the California Air Resources Board to develop by January 2009 a greenhouse gas reduction plan for all industrial sectors. In December 2008, the California Air Resource Board approved a plan for implementing AB 32. The plan contemplates a cap-and-trade program, beginning in 2012. AB32, and any plans, rules and programs approved to implement AB 32, could have a material adverse effect on how we operate our California facilities and the costs of operating the facilities.

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

Federal Regulation of Greenhouse Gases. Various bills have been proposed in Congress to govern CO_2 emissions from generating facilities. Also, in light of the United States Supreme Court ruling in Massachusetts v. EPA that greenhouse gases fit within the Clean Air Act s definition of air pollutant, the EPA may also promulgate regulations regarding the emission of greenhouse gases. Congress or the EPA will likely take action

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to regulate CO_2 within the next several years. The final form of such regulation will be influenced by political and economic factors and is uncertain at this time. Current proposals include a cap-and-trade system that would require us to purchase allowances for the CO_2 emitted by our generating facilities. While we expect that market prices for electricity would increase following such regulation and would allow us to recover most of the cost of these allowances, we cannot predict with any certainty the actual increases in costs such regulation could impose upon us or our ability to recover such cost increases through higher market rates for electricity, and these regulations could have a material adverse effect on our consolidated statements of operations, financial position or cash flows. We expect to produce approximately 18.3 million tons of CO_2 at all of our generating facilities in 2009.

Water Regulations

We are required under the Clean Water Act to comply with intake and discharge requirements, requirements for technological controls and operating practices. To discharge water, we generally need permits required by the Clean Water Act. Such permits typically are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to impose additional and more stringent requirements or limitations in the future. This is particularly the case for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act (the 316 (b) regulations). A 2007 decision by the United States Court of Appeals for the Second Circuit (the Second Circuit) in *Riverkeeper Inc. et al v. EPA*, in which the court remanded to the EPA for reconsideration numerous provisions of the EPA s section 316(b) regulations for existing power plants, has created substantial uncertainty about exactly what technologies or other measures will be needed to satisfy section 316(b) requirements in the future and when any new requirements will be imposed. That decision by the Second Circuit is under review by the United States Supreme Court.

Endangered Species Acts. Mirant Delta s use of water from the Sacramento-San Joaquin Delta at its Contra Costa and Pittsburg generating facilities potentially affects certain fish species protected under the Federal Endangered Species Act and the California Endangered Species Act. Mirant Delta therefore must maintain authorization under both statutes to engage in operations that could result in a take of (i.e., cause harm to) fish of the protected species. In January and February 2006, Mirant Delta received correspondence from the United States Fish and Wildlife Service and the Army Corps of Engineers expressing the view that the Federal Endangered Species Act take authorization for the Contra Costa and Pittsburg facilities was no longer in effect as a result of changed circumstances. Mirant Delta disagreed with the agencies characterization of its take authorization as no longer being in effect. In late October 2007, Mirant Delta received correspondence from the United States Fish and Wildlife Service, the National Marine Fisheries Service and the Army Corps of Engineers clarifying that Mirant Delta continued to be authorized to take four species of fish protected under the Federal Endangered Species Act. The agencies have initiated a process that will review the environmental effects of Mirant Delta s water usage, including effects on the protected species of fish. That process could lead to changes in the manner in which Mirant Delta can use river water for the operation of the Contra Costa and Pittsburg generating facilities.

Mirant and Mirant Delta received two letters, one dated September 27, 2007, sent on behalf of the Coalition for a Sustainable Delta, four water districts, and an individual and the second dated October 16, 2007, sent on behalf of San Francisco Baykeeper (collectively with the parties sending the September 27, 2007, letter, the Noticing Parties), providing notice that the Noticing Parties intend to file suit alleging that Mirant Delta has violated, and continues to violate, the Federal Endangered Species Act through the operation of its Contra Costa and Pittsburg generating facilities. The Noticing Parties contend that the facilities use of water drawn from the Sacramento-San Joaquin Delta for cooling purposes results in harm to four species of fish listed as endangered species. The Noticing Parties assert that Mirant Delta s authorizations to take (i.e., cause harm to) those species, biological opinions and incidental take statements issued by the National Marine Fisheries Service on October 17, 2002, for three of the fish species and the United States Fish and Wildlife Service on November 4, 2002, for the fourth fish species, have been violated by Mirant Delta. Therefore, the notifying parties assert that

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the authorizations for the effects on the four fish species caused by the operation of the Contra Costa and Pittsburg generating facilities are no longer applicable. Following receipt of these letters, in late October 2007, Mirant Delta received correspondence from the United States Fish and Wildlife Service, the National Marine Fisheries Service and the Army Corps of Engineers clarifying that Mirant Delta continued to be authorized to take the four species of fish protected under the Federal Endangered Species Act. The agencies have initiated a process that will review the environmental effects of Mirant Delta s water usage, including effects on the protected species of fish. That process could lead to changes in the manner in which Mirant Delta can use river water for the operation of the Contra Costa and Pittsburg generating facilities. In a subsequent letter, the Coalition for a Sustainable Delta also alleged violations of the National Environmental Policy Act and the California Endangered Species Act associated with the operation of Mirant Delta s facilities. Mirant Delta disputes the allegations made by the Noticing Parties. No lawsuits have been filed to date, and San Francisco Baykeeper on February 1, 2008, withdrew its notice of intent to sue.

Additionally, in September 2007, Mirant Delta signed an amendment to a Memorandum of Agreement with the California Department of Fish and Game. The amendment requires Mirant Delta to initiate monitoring of the effects on fish of the operations of the Contra Costa and Pittsburg generating facilities, to prepare an environmental impact report, and to submit within 24 months an application for a new permit authorizing Mirant Delta to take the protected fish species affected by the operation of its facilities. The amendment extends Mirant Delta s authorization for take of fish species protected under the California Endangered Species Act until the California Department of Fish and Game completes its consideration of the application for the new permit.

Potrero National Pollution Discharge Elimination System Permit. On June 8, 2006, Bayview-Hunters Point Community Advocates and Communities for a Better Environment filed a petition challenging the issuance of the National Pollution Discharge Elimination System (NPDES) permit for our Potrero facility. On February 8, 2007, Bayview-Hunters Point Community Advocates and Communities for a Better Environment filed another petition with a request to amend their initial petition. On March 21, 2007, the California State Water Resources Control Board notified the parties that petitioners requested that as of March 19, 2007, the two petitions be moved from active status to abeyance. Those petitions currently remain in abeyance. Additionally, on June 15, 2007, Bayview-Hunters Point Community Advocates and Communities for a Better Environment and San Francisco Baykeeper filed a third petition requesting that the NPDES permits for Potrero and Mirant Delta s Pittsburg facility be reopened. The State Water Resources Control Board denied that petition on November 27, 2007.

Kendall NPDES and Surface Water Discharge Permit. On September 26, 2006, the EPA issued to Mirant Kendall an NPDES renewal permit for the Kendall generating facility. The same permit was concurrently issued by the MADEP as a state Surface Water Discharge Permit (SWD Permit), and was accompanied by MADEP s earlier issued water quality certificate under section 401 of the Clean Water Act. The new permits impose new temperature limits at various points in the Charles River, an extensive temperature, water quality and biological monitoring program and a requirement to develop and install a barrier net system to reduce fish impingement and entrainment. The provisions regulating the thermal discharge could cause substantial curtailments of the operations of the Kendall facility. Mirant Kendall has appealed the permits in three proceedings: (1) appeal of the NPDES permit to the EPA s Environmental Appeals Board; (2) appeal of the SWD Permit to the MADEP; and (3) appeal of the water quality certification to the MADEP. The effect of the permits has been stayed pending the outcome of these appeals. The two appeals to the MADEP have been stayed pending the outcome of the appeal to the Environmental Appeals Board. On September 28, 2007, the Environmental Appeals Board stayed the appeal proceedings until April 18, 2008, in order for the EPA to address the sections of the permit that are affected by the EPA s suspension of the 316(b) regulations as a result of the 2007 decision by the Second Circuit in *Riverkeeper, Inc. et al. v. EPA.* Subsequent orders by the Environmental Appeals Board have extended that stay to March 6, 2009. On March 6, 2008, the EPA and the MADEP issued a draft permit modification to address the 316(b) provisions of the permit that would require modifications to the intake structure for the Kendall generating facility to add fine and coarse mesh barrier exclusion technologies and to install a mechanism to sweep organisms away from the intake structure through an induced water flow. On May 1, 2008, Mirant

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Kendall submitted comments on the draft permit modification objecting to the new requirements. On December 19, 2008, the EPA and the MADEP issued final permit modifications to address the 316(b) regulations. Those final permit modifications did not substantially modify the requirements proposed in the draft modifications, and on February 2, 2009 Mirant Kendall filed an appeal of those modifications. While the appeals are pending, the effect of any contested permit provisions will be stayed and the Kendall generating facility will continue to operate under its current NPDES permit. We are unable to predict the outcome of these proceedings.

Canal NPDES and SWD Permit. On August 1, 2008, the EPA issued to Mirant Canal an NPDES renewal permit for the Canal generating facility. The same permit was concurrently issued by MADEP as a state SWD Permit, and was accompanied by MADEP s earlier water quality certificate under section 401 of the Clean Water Act. The new permit imposes a requirement on Mirant Canal to install closed cycle cooling or an alternative technology that will reduce the entrainment of marine organisms by the Canal generating facility to levels equivalent to what would be achieved by closed cycle cooling. Mirant Canal appealed the NPDES permit to the EPA s Environmental Appeals Board and appealed the surface water discharge and the water quality certificate to the MADEP. On December 4, 2008, the EPA requested a stay to the appeal proceedings until June 1, 2009 and withdrew provisions related to the closed cycle cooling requirements. The EPA has re-noticed these provisions as draft conditions for additional public comment. Mirant Canal filed comments on January 29, 2009, stating that installing closed cycle cooling at the Canal generating facility was not justified and that without some cost-recovery mechanism the cost would make continued operation of the facility uneconomic. While the appeals of the renewal permit are pending, the effect of any contested permit provisions is stayed and the Canal generating facility will continue to operate under its current NPDES permit. We cannot predict the outcome of this proceeding.

NPDES and State Pollutant Discharge Elimination System Permit Renewals. In addition to the proceedings described above in *Kendall NPDES and Surface Water Discharge Permit* and *Canal NPDES and SWD Permit* related to the renewal of the NPDES permit for the Kendall and Canal facilities, proceedings are currently pending for renewal of the NPDES permits for the Dickerson and Morgantown facilities leased by Mirant Mid-Atlantic, the Chalk Point facility owned by Mirant Chalk Point, three ash sites in Maryland owned by Mirant MD Ash Management, the Potomac River facility owned by Mirant Potomac River, the Contra Costa and Pittsburg facilities owned by Mirant Delta and the Potrero facility owned by Mirant Potrero. A proceeding is also pending for renewal of the State Pollutant Discharge Elimination System (SPDES) permit for the Bowline facility owned by Mirant Bowline.

In general, the EPA and the state agencies responsible for implementing the provisions of the Clean Water Act applicable to the intake of water and discharge of effluent by electric generating facilities have been making the requirements imposed upon such facilities more stringent over time. For example, with respect to the Potrero facility, the California Regional Water Quality Control Board has previously stated its intent not to renew the facility s NPDES permit unless Mirant Potrero can demonstrate that the operation of the facility does not adversely affect the San Francisco Bay. With respect to each of these permit renewal proceedings, the permit renewal proceeding could take years to resolve and the agency or agencies involved could impose requirements upon the Mirant entity owning the facility that require significant capital expenditures, limit the times at which the facility can operate, or increase operations and maintenance costs materially.

Wastes, Hazardous Materials and Contamination

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

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In November 2008, the MDE promulgated new regulations to govern the handling, storage, recycling and disposal of coal combustion byproducts in Maryland. We have challenged portions of these new regulations in state court because they do not provide adequate time for effectuating the required changes to our facilities and they are unclear in many respects.

Additionally, CERCLA, also known as the Superfund law, establishes a federal framework for dealing with the cleanup of contaminated sites. Many states have enacted similar state superfund statutes as well as other laws imposing obligations to investigate and clean up contamination. Our Contra Costa, Pittsburg and Potrero facilities have areas of soil and groundwater contamination subject to CERCLA and the California Health and Safety Code. In 1998, prior to our acquisition of those facilities from PG&E, consultants for PG&E conducted soil and groundwater investigations at those facilities which revealed contamination. The consultants conducting the investigation estimated the aggregate cleanup costs at those facilities could be as much as $60 million. Pursuant to the terms of the Purchase and Sale Agreement with PG&E, PG&E has responsibility for the containment or capping of all soil and groundwater contamination and the disposition of up to 60,000 cubic yards of contaminated soil from the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E s consultants in 1998 at the Contra Costa and Pittsburg generating facilities, before those facilities were purchased in 1999 by our subsidiaries. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil from the Potrero generating facility. We are not aware of soil or groundwater conditions for which we expect remediation costs to be material that are not the responsibility of other parties.

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Employees

At December 31, 2008, we employed 1,661 people, which included approximately 1,146 employees at our generating facilities, 62 employees at our regional offices and 453 employees at our corporate headquarters in Atlanta, Georgia. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Mid-Atlantic Region			
IBEW Local 1900	Maryland and Virginia	530	6/1/2010
Northeast Region			
IBEW Local 503[1]	New York	49	4/30/2013
UWUA Local 369[2]	Cambridge, Massachusetts	34	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	46	6/1/2011
California			
IBEW Local 1245	California	118	10/31/2013
Total		777	

(1) Our previous contract with Local 503 expired on June 1, 2008. After reaching an impasse in negotiations with Local 503, on January 28, 2009, we unilaterally implemented the terms of our final offer to the union. Bargaining unit employees have continued to work under the terms imposed by us without disruption.

(2) We are currently in negotiations with Local 369 on new agreements.

To mitigate and reduce the risk of disruption during labor negotiations, we engage in contingency planning for operation of our generating facilities to the extent possible during an adverse collective action by one or more of our unions.

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Item 1A. ***Risk Factors***

The following are factors that could affect our future performance:

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

We sell capacity, energy and ancillary services from our generating facilities into competitive power markets on a short-term fixed price basis or through power sales agreements. Since mid-2007, our revenues from selling capacity have become a significant part of our overall revenues. Except for our Potrero facility, we are not guaranteed recovery of our costs or any return on our capital investments through mandated rates. The market for wholesale electric energy and energy services reflects various market conditions beyond our control, including the balance of supply and demand, our competitors marginal and long run costs of production, and the effect of market regulation. Being concentrated in a few geographic markets results in concentrated exposure to those markets, especially PJM. The price for which we can sell our output may fluctuate on a day-to-day basis and our ability to transact may be affected by the overall liquidity in the markets in which we operate. The markets in which we compete remain subject to one or more forms of regulation that limit our ability to raise prices during periods of shortage to the degree that would occur in a fully deregulated market and may thereby limit our ability to recover costs and an adequate return on our investment. Our revenues and results of operations are influenced by factors that are beyond our control, including:

- the failure of market regulators to develop and maintain efficient mechanisms to compensate merchant generators for the value of providing capacity needed to meet demand;

- actions by regulators, ISOs, RTOs and other bodies that may prevent capacity and energy prices from rising to the level necessary for recovery of our costs, our investment and an adequate return on our investment;

- legal and political challenges to the rules used to calculate capacity payments in the markets in which we operate;

- the possibility that the appellate court considering the pending appeal of the FERC s rulings that approved the RPM provisions of PJM s tariff does not affirm the FERC s approval of those provisions, resulting in modifications to the capacity payments made under that tariff in the future and possibly refunds for past periods;

- the ability of wholesale purchasers of power to make timely payment for energy or capacity, which may be adversely affected by factors such as retail rate caps, refusals by regulators to allow utilities to recover fully their wholesale power costs and investments through rates, catastrophic losses and losses from investments by utilities in unregulated businesses;

- increases in prevailing market prices for fuel oil, coal, natural gas and emissions allowances that may not be reflected in prices we receive for sales of energy;

- increases in supplies as a result of actions of our current competitors or new market entrants, including the development of new generating facilities or alternative energy sources that may be able to produce electricity less expensively than our generating facilities and improvements in transmission that allow additional supply to reach our markets;

- decreases in energy consumption resulting from demand-side management programs such as automated demand response, which may alter the amount and timing of consumer energy use;

the competitive advantages of certain competitors, including continued operation of older power plants in strategic locations after recovery of historic capital costs from ratepayers;

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- existing or future regulation of our markets by the FERC, ISOs and RTOs, including any price limitations and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;
- regulatory policies of state agencies that affect the willingness of our customers to enter into long-term contracts generally, and contracts for capacity in particular;
- changes in the rate of growth in electricity usage as a result of such factors as national and regional economic conditions and implementation of conservation programs;
- seasonal variations in energy and gas prices and capacity payments; and
- seasonal fluctuations in weather, in particular abnormal weather conditions.

In addition, unlike most other commodities, electric energy can only be stored on a very limited basis and generally must be produced at the time of use. As a result, the wholesale power markets are subject to substantial price fluctuations over relatively short periods of time and can be unpredictable.

The global financial crisis may have an effect on our business and financial condition in ways that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had and may continue to have an effect on our business and our financial condition. For example, in October 2008, Lehman Commercial Paper, Inc., a subsidiary of Lehman Brothers Holdings, Inc. and a lender under the senior secured revolving credit facility of our subsidiary, Mirant North America, filed for bankruptcy. As a result of the Lehman Commercial Paper, Inc. bankruptcy, we expect that the total availability under our senior secured revolving credit facility has decreased from $800 million to $755 million, assuming that Lehman Commercial Paper, Inc. does not honor its $45 million commitment. While we do not expect that the Lehman Commercial Paper, Inc. bankruptcy will have a material adverse effect on Mirant, the credit crisis could negatively affect availability under the Mirant North America senior secured revolving credit facility if other lenders under such facility are forced to file for bankruptcy or are otherwise unable to perform their obligations. Absent significant non-performance of lenders under the existing Mirant North America senior secured revolving credit facility, we think that we have sufficient liquidity for future operations (including potential working capital requirements) and capital expenditures as discussed in Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition Liquidity and Capital Resources. However, in the event of significant non-performance of lenders under the existing Mirant North America senior secured revolving credit facility, the credit crisis could have a negative effect on our ability to obtain new lines of credit if financial institutions are unwilling or unable to enter into new revolving credit facilities.

In addition to the potential effect on our liquidity that could arise from the global financial crisis, the crisis could have a negative effect on the markets in which we sell power, purchase fuel and perform other trading and marketing activities. In recent years, global financial institutions have been active participants in such markets. As such financial institutions consolidate and operate under more restrictive capital constraints in response to the financial crisis, there could be less liquidity in the energy and commodity markets, which could have a negative effect on our ability to hedge and transact with creditworthy counterparties. In addition, we are exposed to credit risk resulting from the possibility that a loss may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement with us. Deterioration in the financial condition of our counterparties as a result of the global financial crisis and the resulting failure to pay amounts owed to us or to perform obligations or services owed to us beyond collateral posted could have a negative effect on our business and financial condition.

Because of the current market design in California our generating facilities may have a limited life unless we make significant capital expenditures to increase their commercial and environmental performance.

Our generating facilities in California depend almost entirely on payments in support of system reliability. The energy market, as currently constituted, will not justify the capital expenditures necessary to repower or

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reconstruct our facilities to make them commercially viable in a merchant market. If a commercially reasonable capacity market were to be instituted by the CAISO or we could obtain a contract with a creditworthy buyer, it is possible that we could justify investing the necessary capital to repower or reconstruct our facilities. Absent that, our generating facilities will be commercially viable only as long as they are necessary for reliability.

Changes in commodity prices may negatively affect our financial results by increasing the cost of producing power or lowering the price at which we are able to sell our power.

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

Our use of derivative financial instruments in our asset management activities will not fully protect us from fluctuations in commodity prices and our risk management policy cannot eliminate the risks associated with these activities.

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

Our asset management activities include natural gas derivative financial instruments that we use to hedge power prices for our baseload generation. The effectiveness of these hedges is dependent upon the correlation between power and natural gas prices in the markets where we operate. If those prices are not sufficiently correlated, our financial results and financial position could be adversely affected.

Additionally, we expect to have an open position in the market, within our established guidelines, resulting from the management of our portfolio. To the extent open positions exist, fluctuating commodity prices can affect our financial results and financial position, either favorably or unfavorably. Furthermore, the risk management procedures we have in place may not always be followed or may not always work as planned. Unauthorized hedging and related activities by our employees could result in significant penalties and financial losses. As a result of these and other factors, we cannot predict the outcome that risk management decisions may have on our business, operating results or financial position. Although management devotes considerable attention to these issues, their outcome is uncertain.

We are exposed to the risk of fuel and fuel transportation cost increases and volatility and interruption in fuel supply because our facilities generally do not have long-term agreements for the supply of natural gas, coal and oil.

Although we attempt to purchase fuel based on our expected fuel requirements, we still face the risks of supply interruptions and fuel price volatility. Our cost of fuel may not reflect changes in energy and fuel prices in part because we must pre-purchase inventories of coal and oil for reliability and dispatch requirements, and thus the price of fuel may have been determined at an earlier date than the price of energy generated from it. The price we can obtain from the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs. This may have a material adverse effect on our financial performance. The volatility of fuel prices could adversely affect our financial results and operations.

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The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in 2007. Global demand for coal to generate electricity has been a significant factor influencing domestic prices for the types of coal that we use. At the same time, the prices for power and natural gas were extremely volatile, increasing during the first half of 2008 and decreasing during the second half of 2008. Fluctuations in natural gas prices have a significant effect on the price of power, especially in the PJM market where the marginal price for power is often set by gas-fired units. In 2008 as compared to 2007, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period.

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013.

Our asset management, proprietary trading and fuel oil management activities may increase the volatility of our quarterly and annual financial results.

We engage in asset management activities to hedge economically our exposure to market risk with respect to: (1) electricity sales from our generating facilities; (2) fuel used by those facilities; and (3) emissions allowances. We generally attempt to balance our fixed-price purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative financial instruments. We also use derivative financial instruments with respect to our limited proprietary trading and fuel oil management activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. Derivatives from our asset management, proprietary trading and fuel oil management activities are recorded on our balance sheet at fair value pursuant to SFAS 133. None of our derivatives recorded at fair value are designated as hedges under SFAS 133 and changes in their fair values are therefore recognized currently in earnings as unrealized gains or losses. As a result, our financial results including gross margin, operating income and balance sheet ratios will, at times, be volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. For a more detailed discussion of the accounting treatment of our asset management, proprietary trading and fuel oil management activities, see Note 4 to our consolidated financial statements contained elsewhere in this report.

Operation of our generating facilities involves risks that may have a material adverse effect on our cash flows and results of operations.

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

- the output and efficiency levels at which those generating facilities perform;
- interruptions in fuel supply and quality of available fuel;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether a result of age or otherwise);
- restrictions on emissions;
- violations of our permit requirements or changes in the terms of or revocation of permits;

releases of pollutants and hazardous substances to air, soil, surface water or groundwater;

ability to transport and dispose of coal ash at reasonable prices;

shortages of equipment or spare parts;

labor disputes;

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- operator errors;
- curtailment of operations because of transmission constraints;
- failures in the electricity transmission system which may cause large energy blackouts;
- implementation of unproven technologies in connection with environmental improvements; and
- catastrophic events such as fires, explosions, floods, earthquakes, hurricanes or other similar occurrences.

If our facilities experience unplanned outages, we may be required to procure replacement power in the open market to satisfy contractual commitments. If we should lack adequate liquidity to post margin and collateral requirements, we may be exposed to significant losses and may miss significant opportunities, and we may have increased exposure to the volatility of spot markets.

A decrease in, or the elimination of, the revenues generated by our facilities or an increase in the costs of operating such facilities could materially affect our cash flows and results of operations, including cash flows available to us to make payments on our debt or our other obligations.

Our operating results are subject to quarterly and seasonal fluctuations.

Our operating results have fluctuated in the past and are likely to continue to do so in the future as a result of a number of factors, including seasonal variations in demand and fuel prices.

We compete to sell energy, capacity and ancillary services in the wholesale power markets against some competitors that enjoy competitive advantages, including the ability to recover fixed costs through rate-base mechanisms and a lower cost of capital.

Regulated utilities in the wholesale markets generally enjoy a lower cost of capital than we do and often are able to recover fixed costs through regulated retail rates, including, in many cases, the costs of generation, allowing them to build, buy and upgrade generating facilities without relying exclusively on market clearing prices to recover their investments. The competitive advantages of such participants could adversely affect our ability to compete effectively and could have an adverse impact on the revenues generated by our facilities.

Our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements, including future changes to them.

Our business is subject to extensive environmental regulations promulgated by federal, state and local authorities, which, among other things, restrict the discharge of pollutants into the air, water and soil, and also govern the use of water from adjacent waterways. Such laws and regulations frequently require us to obtain permits and remain in continuous compliance with the conditions established by those permits. To comply with these legal requirements and the terms of our permits, we must spend significant sums on environmental monitoring, pollution control equipment and emissions allowances. If we were to fail to comply with these requirements, we could be subject to civil or criminal liability, injunctive relief and the imposition of liens or fines. We may be required to shut down facilities (including ash sites) if we are unable to comply with the requirements, or if we determine the expenditures required to comply are uneconomic.

From time to time, we may not be able to obtain necessary environmental regulatory approvals. Such approvals could be delayed or subject to onerous conditions. If there is a delay in obtaining environmental regulatory approval or if onerous conditions are imposed, the operation of our generating facilities or ash sites or the sale of electricity to third parties could be prevented or become subject to additional costs. Such delays or onerous conditions could have a material adverse effect on our financial performance and condition. In addition, environmental laws, particularly with respect to air emissions, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require us to make additional facility upgrades or restrict our operations.

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Increased public concern and growing political pressure related to global warming have resulted in significant increases in the regulation of greenhouse gases, including CO2 at the state level. Future local, state and federal regulation of greenhouse gases is likely to create substantial environmental costs for us in the form of taxes or purchases of emissions allowances. Many of the states where we own generating facilities, including California, Maryland, Massachusetts and New York, have recently committed, or expressed an intent to commit, to mandatory reductions in statewide CO2 emissions through a regional cap-and-trade program. Maryland, Massachusetts and New York have already joined the RGGI, which required all allowances to be purchased initially through an auction process, the first of which took place in September 2008. Auctions, such as those mandated by the RGGI, may decrease the amount of available allowances and substantially increase emissions allowance prices. Because our generating facilities emit CO2, these regulations and similar future laws may significantly increase our operating costs.

Certain environmental laws, including CERCLA and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of remediating contamination in soil, groundwater and elsewhere. Some of our facilities have areas with known soil and/or groundwater contamination. Releases of hazardous substances at our generating facilities, or at locations where we dispose of (or in the past disposed of) hazardous substances and other waste, could require us to spend significant sums to remediate contamination, regardless of whether we caused such contamination. The discovery of significant contamination at our generating facilities, at disposal sites we currently use or have used, or at other locations for which we may be liable, or the failure or inability of parties contractually responsible to us for contamination to respond when claims or obligations regarding such contamination arise, could have a material adverse effect on our financial performance and condition.

Major environmental construction projects planned by 2010 at our Mid-Atlantic coal facilities may not meet their anticipated schedule, which would restrict these units from running at their maximum economic levels. If the operating constraints were sufficiently severe, Mirant Mid-Atlantic may not have sufficient cash flow to permit it to make distributions or, if more severe, to meet its obligations.

Under the Maryland Healthy Air Act, we are required to reduce annual emissions below certain levels by January 2010. The levels established do not allow for the use of emissions allowances to meet the mandated levels. To meet these requirements, we are installing pollution control equipment on all of our Maryland coal-fired units. We may not have completed installation of or be able to operate this pollution control equipment by January 2010 because of a number of factors, including:

- adverse weather conditions;
- unanticipated cost increases;
- engineering problems;
- construction problems;
- failure or delays in obtaining necessary permits and approvals;
- shortages of equipment, materials or skilled labor;
- unscheduled delays in delivery of materials and equipment; and
- work stoppages.

Any of these factors may significantly increase the estimated costs of our environmental construction projects or result in a loss of cash flows from operations because of reduced unit operations.

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

We expect that certain of our generating facilities and related properties will become subject to decommissioning and/or site remediation obligations that may require material expenditures. Furthermore, laws and regulations may change to impose material additional decommissioning and remediation obligations on us in the future. If we are required to make material expenditures to decommission or remediate one or more of our facilities, such obligations will affect our cash flows and may adversely affect our ability to make payments on our obligations.

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

As of December 31, 2008, our consolidated indebtedness was $2.676 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $1.0 billion (assuming a 10% discount rate) and the termination value of the Mirant Mid-Atlantic leveraged leases is $1.4 billion. Our leverage and obligations under the leveraged leases could have important consequences, including the following: (1) it may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; (2) a substantial portion of our cash flows from operations must be dedicated to the payment of principal and interest on our indebtedness and will not be available for other purposes, including our operations, capital expenditures and future business opportunities; (3) the debt service requirements of our indebtedness could make it more difficult for us to satisfy or refinance our financial obligations; (4) certain of our borrowings, including borrowings under our senior secured credit facilities, are at variable rates of interest, exposing us to the risk of increased interest rates; (5) it may limit our ability to adjust to changing market conditions and place us at a competitive disadvantage compared with our competitors that have less debt and are not burdened by such obligations and restrictions; and (6) we may be more vulnerable in a downturn in general economic conditions or in our business and we may be unable to carry out capital expenditures that are important to our long-term growth or necessary to comply with environmental regulations.

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

We and certain of our subsidiaries, including Mirant Americas Generation and Mirant North America, are holding companies and, as a result, we are dependent upon dividends, distributions and other payments from our operating subsidiaries to generate the funds necessary to meet our obligations. The ability of certain of our subsidiaries to pay dividends and distributions is restricted under the terms of their debt or other agreements. In particular, a significant portion of cash from our operations is generated by the power generating facilities of Mirant Mid-Atlantic. Under the Mirant Mid-Atlantic leveraged leases, Mirant Mid-Atlantic is subject to a covenant that restricts its right to make distributions to its immediate parent, Mirant North America. In turn, Mirant North America is subject to covenants that restrict its ability to make distributions to its parent, Mirant Americas Generation. The ability of Mirant North America and Mirant Mid-Atlantic to satisfy the criteria set forth in their respective debt covenants in the future could be impaired by factors which negatively affect their financial performance, including interruptions in operation or curtailment of operations to comply with environmental restrictions, significant capital and other expenditures and adverse conditions in the power and fuel markets. Further, the Mirant North America senior notes and senior secured credit facilities include financial covenants that will exclude from the calculation the financial results of any subsidiary that is unable to make distributions or dividends at the time of such calculation. Thus, the inability of Mirant Mid-Atlantic to make distributions to Mirant North America under the leveraged lease transaction would have a material adverse effect on the calculation of the financial covenants under the senior notes and senior secured credit facilities of Mirant North America, including the leverage and interest coverage maintenance covenants under its senior credit facility.

The obligations of Mirant Corporation and its holding company subsidiaries, including the indebtedness of Mirant Americas Generation and Mirant North America, are effectively subordinated to the obligations or

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indebtedness of their respective subsidiaries, including the Mirant Mid-Atlantic leveraged leases. See Item 7. Management s Discussion and Analysis Liquidity and Capital Resources for a discussion of restrictions on the ability of Mirant North America to make distributions to its parent, Mirant Americas Generation.

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

Our ability to pay principal and interest on our debt depends on our future operating performance. If our cash flows and capital resources are insufficient to allow us to make scheduled payments on our debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital, restructure or refinance. There can be no assurance that the terms of our debt will allow these alternative measures, that the financial markets will be available to us on acceptable terms or that such measures would satisfy our scheduled debt service obligations.

We seek to manage the risks associated with the volatility in the price at which we sell power produced by our generating facilities and in the prices of fuel, emissions allowances and other inputs required to produce such power by entering into hedging transactions. These asset management activities may require us to post collateral either in the form of cash or letters of credit. As of December 31, 2008, we had approximately $111 million of posted cash collateral and $301 million of letters of credit outstanding primarily to support our asset management activities, debt service and rent reserve requirements and other commercial arrangements. See Note 10 to our consolidated financial statements contained elsewhere in this report for further information on our posted cash collateral and letters of credit. While we seek to structure transactions in a way that reduces our potential liquidity needs for collateral, we may be unable to execute our hedging strategy successfully if we are unable to post the amount of collateral required to enter into and support hedging contracts.

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

Our business is subject to complex government regulations. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the costs of operating our facilities or our ability to operate our facilities. Such costs, in turn, may negatively affect our results of operations and financial condition.

We are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state agencies regarding physical aspects of our generating facilities. The majority of our generation is sold at market prices under market-based rate authority granted by the FERC. If certain conditions are not met, the FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of our market-based rate authority could have a materially negative impact on our generating business.

Even where market-based rate authority has been granted, the FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires such potential market power to be mitigated. In addition to direct regulation by the FERC, most of our facilities are subject to rules and terms of participation imposed and administered by various ISOs and RTOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, ISOs and RTOs may impose bidding and scheduling rules, both to curb the potential exercise of market power and to ensure market functions. Such actions may materially affect our ability to sell and the price we receive for our energy, capacity and ancillary services.

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To conduct our business, we must obtain and periodically renew licenses, permits and approvals for our facilities. These licenses, permits and approvals can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain and comply with all necessary licenses, permits and approvals for these facilities. If we cannot comply with all applicable regulations, our business, results of operations and financial condition could be adversely affected.

We cannot predict whether the federal or state legislatures will adopt legislation relating to the restructuring of the energy industry. There are proposals in many jurisdictions that would either roll back or advance the movement toward competitive markets for the supply of electricity, at both the wholesale and retail levels. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could affect our ability to compete successfully, and our business and results of operations could be adversely affected. We cannot provide assurance that the introductions of new laws, or other future regulatory developments, will not have a material adverse impact on our business, operations or financial condition.

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

We generate electricity using fossil fuels at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in those technologies will reduce their costs to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

Terrorist attacks, future wars or risk of war may adversely affect our results of operations, our ability to raise capital or our future growth.

As power generators, we face heightened risk of an act of terrorism, either a direct act against one of our generating facilities or an inability to operate as a result of systemic damage resulting from an act against the transmission and distribution infrastructure that is used to transport our power. If such an attack were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, such an attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

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

Our operations are subject to many hazards associated with the power generating industry, which may expose us to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquake, flood, storm surge, lightning, hurricane and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations. These hazards can cause significant injury to personnel or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot assure that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial results and our financial condition.

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We are currently involved in significant litigation that, if decided adversely to us, could materially adversely affect our results of operations and profitability.

We are currently involved in various litigation matters, which are described in more detail in this Form 10-K. We intend to defend vigorously against those claims that we are unable to settle, but the results of this litigation cannot be determined. Adverse outcomes for us in this litigation could require significant expenditures by us and could have a material adverse effect on our results of operations and profitability.

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

None.

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Item 2. ***Properties***

The properties below were owned or leased as of December 31, 2008. Our leasehold or ownership interest is 100% for each property.

Generating Facilities	Location	Dispatch Type	Primary Fuel	Total MW(1)	2008 Net Capacity Factor
Mid-Atlantic Region:					
Chalk Point	Maryland	Intermediate/Baseload/ Peaking	Natural Gas/Coal/Oil	2,413	21%
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	849	37%
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	1,486	53%
Potomac River	Virginia	Intermediate/Baseload	Coal	482	19%
Total Mid-Atlantic				5,230	33%
Northeast Region:					
Canal	Massachusetts	Intermediate	Natural Gas/Oil	1,126	17%
Kendall	Massachusetts	Baseload/Peaking	Natural Gas/Oil	256	39%
Martha s Vineyard	Massachusetts	Peaking	Diesel	14	3%
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	1,139	2%
Total Northeast				2,535	13%
California:					
Contra Costa	California	Intermediate	Natural Gas	674	3%
Pittsburg	California	Intermediate	Natural Gas	1,311	2%
Potrero	California	Intermediate/Peaking	Natural Gas/Diesel	362	17%
Total California				2,347	4%
Total Operations				10,112	21%

(1) Total MW amounts reflect nominal net summer capacity for 2008.

We also own an oil pipeline, which is approximately 51.5 miles long and serves the Chalk Point and Morgantown generating facilities.

Item 3. ***Legal Proceedings***

See Note 16 to our consolidated financial statements contained elsewhere in this report for discussion of the material legal proceedings to which we are a party.

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***

Common Stock

All shares of Old Mirant s common stock were cancelled on January 3, 2006, and 276.5 million shares of New Mirant common stock were distributed to holders of unsecured claims and equity securities. In addition, we reserved 23.5 million shares for unresolved claims, of which approximately 850,000 shares had not yet been distributed as of December 31, 2008. New Mirant is authorized to issue 1.5 billion shares of common stock having a par value of $.01 per share and 100 million shares of preferred stock having a par value of $.01 per share. On January 3, 2006, New Mirant also issued Series A Warrants and Series B Warrants, expiring January 3, 2011, which entitled their holders to purchase, as of that date, an aggregate of 35.3 million and 17.6 million shares of common stock, respectively. The exercise price of the Series A Warrants and Series B Warrants is $21.87 and $20.54 per share, respectively. There were approximately 26.9 million Series A Warrants and 7.1 million Series B Warrants outstanding at December 31, 2008.

All of the New Mirant common stock was issued in accordance with Section 1145 of the Bankruptcy Code, and we received no proceeds from such issuance. The issuance of shares of New Mirant common stock was exempt from the registration requirements of the Securities Act, as amended, and equivalent provisions of state securities laws, in reliance upon Section 1145(a) of the Bankruptcy Code.

Our common stock is currently traded on the NYSE under the ticker symbol MIR. We have submitted to the NYSE our 2008 annual certificate from our Chief Executive Officer certifying that he is not aware of any violation by the Company of NYSE corporate governance listing standards. The closing price of our stock on December 31, 2008, was $18.87. The following table sets forth the high and low prices for our common stock as reported by the NYSE for the periods indicated.

Price Range of Common Stock

Quarter	High	Low
2007		
First	$ 41.70	$ 30.41
Second	$ 49.00	$ 39.61
Third	$ 44.20	$ 34.77
Fourth	$ 44.61	$ 36.20
2008		
First	$ 39.53	$ 33.75
Second	$ 42.21	$ 36.08
Third	$ 39.20	$ 17.32
Fourth	$ 20.28	$ 11.99

Holders

As of January 31, 2009, there were approximately 58,770 record holders of our common stock, par value $.01 per share.

Dividends

We have not paid or declared any cash dividends on our common stock in the last two fiscal years and we do not anticipate paying any quarterly cash dividends in the foreseeable future.

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Return of Cash

On November 9, 2007, we announced that we planned to return a total of $4.6 billion of excess cash to our stockholders based on four factors: (1) the outlook for the business, (2) preserving our credit profile, (3) maintaining adequate liquidity, including for capital expenditures and (4) maintaining sufficient working capital. On September 22, 2008, we announced that we had returned $3.856 billion of cash to our stockholders and suspended our program to return excess cash to our stockholders based on our evaluation of the four factors that were set out upon commencement of the share repurchase program. On November 7, 2008, we announced that we were resuming our program of returning excess cash to our stockholders and would purchase an additional $200 million of shares through open market purchases. This $200 million was completed in the fourth quarter of 2008 and was in addition to the previous $3.856 billion of cash returned to our stockholders.

On November 9, 2007, we announced that the first stage of the cash distribution would be accomplished through an accelerated share repurchase program for $1 billion, plus open market purchases for up to an additional $1 billion. In the fourth quarter of 2007, we repurchased 26.66 million shares of common stock for $1 billion through the accelerated share repurchase program.

On February 29, 2008, we announced that we had decided to return the remaining $2.6 billion of cash through open market purchases of common stock but that we would continue to evaluate the most efficient method to return the cash to stockholders.

On May 15, 2008, the accelerated share repurchase program was completed and we received an additional 682,387 shares, resulting in a total of 27.34 million shares purchased. The final price of shares repurchased under the accelerated share repurchase program was $36.57 per share, which was determined based on a discount to the volume weighted average trading price of our common stock over the period of the accelerated share repurchase program.

Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. We have repurchased approximately 48% of the 256 million basic shares that we had outstanding when the program began in November 2007.

Share Repurchases

The following table sets forth information regarding repurchases by us of our common shares on the NYSE during the three-month period ended December 31, 2008:

Period	Shares repurchased (in millions)	Average price paid per share	Total number of shares purchased as part of publicly announced plans (in millions)	Approximate dollar value of shares that may yet be purchased under the plans (in millions)
Oct 1, 2008 Oct 31, 2008		$		$
Nov 1, 2008 Nov 30, 2008	10.46	$ 16.57	10.46	$ 26.71
Dec 1, 2008 Dec 31, 2008	1.48	$ 18.04	1.48	$
Total	11.94		11.94	

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Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth the compensation plans under which our equity securities were authorized for issuance as of December 31, 2008:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (in millions)	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities to be issued upon exercise of outstanding options, warrants and rights) (in millions)
Equity compensation plans approved by security holders	6.3	$ 29.46	12.3
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	6.3	$ 29.46	12.3

Our 2005 Omnibus Incentive Plan for certain employees and directors of Mirant became effective on January 3, 2006, and is deemed to have been approved by our stockholders by virtue of its approval under the Plan.

Stock Performance Graph

The performance graph below is being provided as furnished and not filed as permitted by 17 Code of Federal Regulations 229.201(e), in this Form 10-K and compares the cumulative total stockholder return on our common stock with the Standard & Poor s 500 Index, the Standard & Poor s Multi-Utility Index and the Standard & Poor s Independent Power Producers and Energy Traders Index since the re-issuance of our common stock in connection with our emergence from bankruptcy on January 3, 2006. Our stock was re-listed on the NYSE on January 11, 2006. Because all of Old Mirant s outstanding common stock was cancelled upon emergence from bankruptcy, stock performance prior to 2006 does not provide a meaningful comparison for current stockholders and thus has not been provided. The graph assumes that $100 was invested on January 11, 2006, in our common stock and each of the above indices, and that all dividends are reinvested. The stockholder return shown below may not be indicative of future performance.

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Indexed Returns

Year Ended

Company / Index	12/31/2006	12/31/2007	12/31/2008
Mirant	$ 126.38	$ 156.04	$ 75.54
S&P 500 Index	$ 111.69	$ 117.82	$ 74.23
S&P 500 Multi-Utilities Index	$ 115.41	$ 127.95	$ 96.80
S&P 500 Independent Power Producers & Energy Traders	$ 125.03	$ 157.71	$ 48.70

Total Return to Stockholders

(Includes reinvestment of dividends)

Annual Return Percentage

Year Ended

Company / Index	12/31/2006	12/31/2007	12/31/2008
Mirant	26.38%	23.47%	(51.59)%
S&P 500 Index	11.69%	5.49%	(37.00)%
S&P 500 Multi-Utilities Index	15.41%	10.86%	(24.34)%
S&P 500 Independent Power Producers & Energy Traders	25.03%	26.13%	(69.12)%

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

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

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions except per share data)				
Statements of Operations Data:					
Operating revenues	$ 3,188	$ 2,019	$ 3,087	$ 2,620	$ 3,231
Income (loss) from continuing operations	1,215	433	1,752	(1,385)	(9)
Income (loss) from discontinued operations	50	1,562	112	93	(467)
Cumulative effect of changes in accounting principles				(15)	
Net income (loss)	1,265	1,995	1,864	(1,307)	(476)
Basic EPS per common share from continuing operations	$ 6.53	$ 1.72	$ 6.15	N/A	N/A

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

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
Unrealized gains (losses) included in operating revenues	$ 840	$ (564)	$ 757	$ (92)	$ 176
Unrealized losses (gains) included in cost of fuel, electricity and other products	54	(28)	102	(76)	8
Total	$ 786	$ (536)	$ 655	$ (16)	$ 168

Our Statement of Operations Data for the year ended December 31, 2007, reflects gains on sales of discontinued operations as discussed in Note 11 to our consolidated financial statements contained elsewhere in this report. EPS information for years prior to 2006 has not been presented because the information is not relevant in any material respect for users of our financial statements. See Note 13 to our consolidated financial statements contained elsewhere in this report for additional information. Our Statement of Operations Data for the year ended December 31, 2006, reflects significant income tax benefits as discussed in Note 7 to our consolidated financial statements contained elsewhere in this report.

Our Statement of Operations Data for the year ended December 31, 2005, reflects the effects of accounting for the Plan confirmed on December 9, 2005. During our bankruptcy proceedings, our consolidated financial statements were prepared in accordance with SOP 90-7. Our Statement of Operations Data for the year ended December 31, 2004, does not include interest expense on debt that was subject to compromise subsequent to the Petition Date and includes goodwill impairment losses of $582 million.

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The consolidated Balance Sheet Data for years 2006, 2005 and 2004, segregates pre-petition liabilities subject to compromise from those liabilities that were not subject to compromise.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
Balance Sheet Data:					
Total assets	$ 10,688	$ 10,538	$ 12,845	$ 14,364	$ 11,926
Total long-term debt	2,676	3,095	3,275	2,582	38
Liabilities subject to compromise			18	18	9,164
Stockholders equity (deficit)	$ 3,762	$ 5,310	$ 4,443	$ 3,856	$ (1,318)

The debt of Mirant Americas Generation that was reinstated in 2005 is included in liabilities subject to compromise for 2004. In 2005, we recorded the effects of the Plan. As a result, liabilities subject to compromise at December 31, 2005 and 2006, only reflect the liabilities of our New York entities that remained in bankruptcy at that time. Total assets for all periods reflect our election in 2008 to discontinue the net presentation of assets subject to master netting agreements upon adoption of FSP FIN 39-1.

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

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

Overview

We are a competitive energy company that produces and sells electricity in the United States. We own or lease 10,112 MW of net electric generating capacity in the Mid-Atlantic and Northeast regions and in California. We also operate an integrated asset management and energy marketing organization based in Atlanta, Georgia.

Share Repurchases

Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. We have repurchased approximately 48% of the 256 million basic shares that we had outstanding when the program began in November 2007. See Note 13 to our consolidated financial statements contained elsewhere in this report for additional information related to our share repurchases.

Hedging Activities

We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our Northeast gas and oil-fired generation through OTC transactions. However, we generally do not hedge our intermediate and peaking units for tenors greater than 12 months. A significant portion of our hedges are financial swap transactions between Mirant Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. At February 10, 2009, our aggregate hedge levels based on expected generation for each period were as follows:

	Aggregate Hedge Levels Based on Expected Generation				
	2009	**2010**	**2011**	**2012**	**2013**
Power	96%	62%	22%	24%	24%
Fuel	90%	64%	53%	29%	6%

Capital Expenditures and Capital Resources

Including amounts already spent to date, we expect to incur total capital expenditures of $1.674 billion to comply with the limitations on SO2, NOx and mercury emissions under the Maryland Healthy Air Act. As of December 31, 2008, we have paid approximately $997 million for capital expenditures related to the Maryland Healthy Air Act. For the year ended December 31, 2008, we paid $683 million for capital expenditures, excluding capitalized interest, of which $497 million related to the Maryland Healthy Air Act. The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest, for 2009 and 2010 (in millions):

	2009	**2010**
Maryland Healthy Air Act	$ 490	$ 187
Other environmental	33	33
Maintenance	162	132
Construction	55	55
Other	14	15
Total	$ 754	$ 422

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We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures.

Consolidated Financial Performance

We reported net income of $1.265 billion, $1.995 billion and $1.864 billion for the years ended December 31, 2008, 2007 and 2006, respectively. The change in net income is detailed as follows (in millions):

	Years Ended December 31,					
	2008	2007	Increase/ (Decrease)	2007	2006	Increase/ (Decrease)
Realized gross margin	$ 1,343	$ 1,643	$ (300)	$ 1,643	$ 1,281	$ 362
Unrealized gross margin	786	(536)	1,322	(536)	655	(1,191)
Total gross margin	2,129	1,107	1,022	1,107	1,936	(829)
Operating Expenses:						
Operations and maintenance	683	707	(24)	707	592	115
Depreciation and amortization	144	129	15	129	137	(8)
Impairment losses		175	(175)	175	119	56
Gain on sales of assets, net	(39)	(45)	6	(45)	(49)	4
Total operating expenses	788	966	(178)	966	799	167
Operating income	1,341	141	1,200	141	1,137	(996)
Total other expense (income), net	124	(299)	423	(299)	99	(398)
Income from continuing operations before reorganization items, net and income taxes	1,217	440	777	440	1,038	(598)
Reorganization items, net		(2)	2	(2)	(164)	162
Provision (benefit) for income taxes	2	9	(7)	9	(550)	559
Income from continuing operations	1,215	433	782	433	1,752	(1,319)
Income from discontinued operations	50	1,562	(1,512)	1,562	112	1,450
Net income	$ 1,265	$ 1,995	$ (730)	$ 1,995	$ 1,864	$ 131

The following discussion includes non-GAAP financial measures because we present our consolidated financial performance in terms of gross margin. Gross margin is our operating revenue less cost of fuel, electricity and other products, and excludes depreciation and amortization. We present gross margin, excluding depreciation and amortization, and realized gross margin separately from unrealized gross margin in order to be consistent with how we manage our business. Therefore, it may not be possible to compare our non-GAAP financial measures with those of other companies which also present similar non-GAAP financial measures. We encourage our investors to review our consolidated financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

Commodity Prices

The prices for power, natural gas and fuel oil were extremely volatile during 2008. For the year ended December 31, 2008, we recognized unrealized gains of $786 million. We are generally economically neutral for that portion of the portfolio that we have hedged because our realized gross margin will reflect the contractual prices of our power and fuel contracts.

Our coal supply comes primarily from the Central Appalachian and Northern Appalachian coal regions. The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in the same period in 2007. Global demand for coal to generate electricity was a significant factor influencing domestic prices for the types of coal that we use. Coal prices in other regions did not increase as dramatically; however, switching the types of coal that we use would require significant capital expenditures and increases in transportation costs. As a result of the increases in market prices, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference

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between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period. We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013. Most of our coal contracts are not required to be recorded at fair value under SFAS 133. As such, these contracts are not included in derivative contract assets and liabilities in the accompanying consolidated balance sheets. As of December 31, 2008, the net fair value of these long-term coal agreements was approximately $38 million.

Results of Operations

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business.

In the tables below, the Mid-Atlantic region includes our Chalk Point, Dickerson, Morgantown and Potomac River facilities. The Northeast region includes our Bowline, Canal, Kendall, Lovett (shutdown on April 19, 2008) and Martha s Vineyard facilities. The California region includes our Contra Costa, Pittsburg and Potrero facilities. Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest on our invested cash balances. For the years ended December 31, 2007 and 2006, Other Operations also includes gains and losses related to the Back-to-Back Agreement with Pepco, which was terminated pursuant to a settlement agreement that became effective in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

Operating Statistics

The following table summarizes Net Capacity Factor by region for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,					
	2008	**2007**	**Decrease**	**2007**	**2006**	**Increase/ (Decrease)**
Mid-Atlantic	33%	37%	(4)%	37%	36%	1%
Northeast	13%	22%	(9)%	22%	18%	4%
California	4%	4%	%	4%	6%	(2)%
Total	21%	25%	(4)%	25%	24%	1%

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The following table summarizes power generation volumes by region for the years ended December 31, 2008, 2007 and 2006 (in gigawatt hours):

	Years Ended December 31, 2008	Years Ended December 31, 2007	Increase/ (Decrease)	Increase/ (Decrease) %	Years Ended December 31, 2007	Years Ended December 31, 2006	Increase/ (Decrease)	Increase/ (Decrease) %
Mid-Atlantic:								
Baseload	14,350	15,390	(1,040)	(7)%	15,390	15,662	(272)	(2)%
Intermediate	489	1,105	(616)	(56)%	1,105	736	369	50%
Peaking	160	337	(177)	(53)%	337	210	127	60%
Total Mid-Atlantic	14,999	16,832	(1,833)	(11)%	16,832	16,608	224	1%
Northeast:								
Baseload	1,131	2,691	(1,560)	(58)%	2,691	2,757	(66)	(2)%
Intermediate	1,919	2,814	(895)	(32)%	2,814	1,896	918	48%
Peaking	5	5		%	5	15	(10)	(67)%
Total Northeast	3,055	5,510	(2,455)	(45)%	5,510	4,668	842	18%
California:								
Intermediate	868	804	64	8%	804	1,102	(298)	(27)%
Peaking	21	18	3	17%	18	34	(16)	(47)%
Total California	889	822	67	8%	822	1,136	(314)	(28)%
Total Mirant	18,943	23,164	(4,221)	(18)%	23,164	22,412	752	3%

The decrease in power generation volumes for the year ended December 31, 2008, as compared to the year ended December 31, 2007, is primarily the result of the following:

- a decrease in Mid-Atlantic as a result of contracting dark spreads, lower demand and second quarter 2008 planned outages to allow for the installation of emissions control equipment as part of our compliance with the Maryland Healthy Air Act.
- a decrease in Northeast as a result of higher fuel prices at times making it uneconomic for certain units to generate, the shutdown of units 3 and 4 of the Lovett generating facility in April 2007 and the shutdown of unit 5 of the Lovett generating facility in April 2008.

The increase in power generation volumes for the year ended December 31, 2007, as compared to the year ended December 31, 2006, is primarily the result of the following:

- an increase in Mid-Atlantic intermediate and peaking generation volumes as a result of favorable spreads between the cost of oil used to generate one MWh of electricity and the market value of the electricity generated (oil conversion spreads   ) in 2007 as compared to 2006.
- an increase in Northeast intermediate generation as a result of increased demand in 2007.

Through the end of 2006, the majority of our California units were subject to RMR arrangements with the CAISO. Since that time, all of our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units. All of the Potrero units continue to be subject to RMR arrangements. Therefore, changes in power generation volumes from those facilities, which can be caused by weather, planned outages, or other factors, do not generally affect our gross margin.

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2008 versus 2007

Gross Margin Overview

The following table details realized and unrealized gross margin by operating segments (in millions):

	Years Ended December 31,					
	2008			2007		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Mid-Atlantic	$ 1,038	$ 676	$ 1,714	$ 1,084	$ (479)	$ 605
Northeast	189	(10)	179	280	(43)	237
California	127		127	135		135
Other Operations	(17)	120	103	126	(14)	112
Eliminations	6		6	18		18
Total	$ 1,343	$ 786	$ 2,129	$ 1,643	$ (536)	$ 1,107

Gross margin for the years ended December 31, 2008 and 2007, is further detailed as follows (in millions):

	Year Ended December 31, 2008					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 517	$ 73	$ 4	$ (17)	$ 6	$ 583
Contracted and capacity	340	90	123			553
Realized value of hedges	181	26				207
Total realized gross margin	1,038	189	127	(17)	6	1,343
Unrealized gross margin	676	(10)		120		786
Total gross margin	$ 1,714	$ 179	$ 127	$ 103	$ 6	$ 2,129

	Year Ended December 31, 2007					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 686	$ 128	$ 3	$ 109	$ 18	$ 944
Contracted and capacity	196	87	132	17		432
Realized value of hedges	202	65				267
Total realized gross margin	1,084	280	135	126	18	1,643
Unrealized gross margin	(479)	(43)		(14)		(536)
Total gross margin	$ 605	$ 237	$ 135	$ 112	$ 18	$ 1,107

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

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts, through tolling agreements, and from ancillary services. For the year ended December 31, 2007, contracted and capacity also included the Back-to-Back Agreement, which was terminated on August 10, 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

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

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Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts that are recorded as derivative contract assets and liabilities on our consolidated balance sheets, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Our gross margin for the year ended December 31, 2008, was $2.129 billion as compared to $1.107 billion for the same period in 2007. The increase in gross margin, which includes net unrealized gains and losses from our hedging activities, was principally a result of the following:

An increase of $1.322 billion in unrealized gross margin was comprised of the following:

- unrealized gains of $786 million in 2008, which include a $460 million net increase in the value of hedge contracts for future periods primarily related to changes in forward power and natural gas prices in 2008 and $326 million from the settlement of power and fuel contracts during the period for which net unrealized losses had been recorded in prior periods; and

- unrealized losses of $536 million in 2007, which include $438 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $98 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007.

A decrease of $300 million in realized gross margin primarily attributable to:

- a decrease in energy of $361 million as a result of an increase in fuel prices, lower generation volumes and a decrease in the contribution of proprietary trading and fuel oil management activities, partially offset by an increase in power prices and a decrease in the cost of emissions allowances;

- a decrease of $60 million in realized value of hedges as a result of a decrease in the settlement value of power hedges, reduced by an increase in the amount by which market prices for coal exceeded the contract prices for the coal that we purchased under our long-term agreements; partially offset by

- an increase in contracted and capacity of $121 million primarily resulting from a full year of PJM RPM capacity payments in 2008 in the Mid-Atlantic. The contracted and capacity gross margin for 2007 includes a refund to us of $36 million for payments made under the Back-to-Back Agreement for periods after May 31, 2006, as a result of the Pepco Settlement Agreement becoming fully effective in August 2007.

Mid-Atlantic

Our Mid-Atlantic segment, which accounts for approximately 50% of our net generating capacity, includes four generating facilities with total net generating capacity of 5,230 MW.

The following tables summarize the results of operations of our Mid-Atlantic segment (in millions):

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Realized gross margin	$ 1,038	$ 1,084	$ (46)
Unrealized gross margin	676	(479)	1,155
Total gross margin	1,714	605	1,109
Operating Expenses:			

Operations and maintenance	412	360	52
Depreciation and amortization	92	81	11
Gain on sales of assets, net	(8)		(8)
Total operating expenses	496	441	55
Operating income	1,218	164	1,054
Total other expense (income), net	1	(5)	6
Income from continuing operations before reorganization items, net and income taxes	$ 1,217	$ 169	$ 1,048

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Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ 517	$ 686	$ (169)
Contracted and capacity	340	196	144
Realized value of hedges	181	202	(21)
Total realized gross margin	1,038	1,084	(46)
Unrealized gross margin	676	(479)	1,155
Total gross margin	$ 1,714	$ 605	$ 1,109

The decrease of $46 million in realized gross margin was principally a result of the following:

a decrease of $169 million in energy, primarily as a result of a substantial increase in the price of coal, partially offset by an increase in power prices and a decrease in the cost of emissions allowances. The decrease in energy also includes a $13 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008. In addition, generation volumes decreased 11% as a result of contracting dark spreads, lower demand that resulted in less generation from our intermediate and peaking facilities and second quarter 2008 planned outages to allow for the installation of emissions control equipment as part of our compliance with the Maryland Healthy Air Act;

a decrease of $21 million in realized value of hedges primarily as a result of a decrease in the settlement value of power hedges. In 2008, the average market prices for power exceeded the settlement value of power contracts. In 2007, the settlement value of power contracts exceeded market prices. The decrease in power hedges was partially offset by an increase in the amount by which market prices for coal exceeded the contract prices for the coal that we purchased under our long-term agreements; partially offset by

an increase of $144 million in contracted and capacity primarily related to higher capacity revenues for 2008 as a result of the commencement of the PJM RPM capacity market in June 2007.

The increase of $1.155 billion in unrealized gross margin was comprised of the following:

unrealized gains of $676 million in 2008, which include a $399 million net increase in the value of hedge contracts for future periods primarily related to changes in forward power and natural gas prices in 2008 and an increase of $277 million from power and fuel contracts that settled during the period for which net unrealized losses had been recorded in prior periods; and

unrealized losses of $479 million in 2007, which include $270 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $209 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007.

Operating Expenses

The increase of $55 million in operating expenses is primarily a result of the following:

an increase of $52 million in operations and maintenance expense, which includes:

an increase of $29 million related to the timing of our planned outages and an increase in labor and chemical costs related to our pollution control equipment; and

$23 million in increased allocated corporate overhead costs. With the completion of several dispositions by Mirant in the second and third quarters of 2007 and the shutdown of units 3 and 4 of the Lovett generating facility in the second quarter of 2007, Mirant Mid-Atlantic received a greater allocation of Mirant s corporate overhead costs in the year ended December 31, 2008, than in the same period in 2007;

an increase of $11 million in depreciation and amortization expense related to pollution control equipment placed in service as part of our compliance with the Maryland Healthy Air Act; partially offset by

an increase of $8 million in gain on sales of assets, net primarily as a result of the sales of emissions allowances in 2008.

Northeast

Our Northeast segment is comprised of our three generating facilities located in Massachusetts and one generating facility located in New York with total net generating capacity of 2,535 MW.

The following tables summarize the results of operations of our Northeast segment (in millions):

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Realized gross margin	$ 189	$ 280	$ (91)
Unrealized gross margin	(10)	(43)	33
Total gross margin	179	237	(58)
Operating Expenses:			
Operations and maintenance	167	179	(12)
Depreciation and amortization	19	25	(6)
Impairment losses		175	(175)
Gain on sales of assets, net	(30)	(49)	19
Total operating expenses	156	330	(174)
Operating income (loss)	23	(93)	116
Total other income, net	(1)	(7)	6
Income (loss) from continuing operations before reorganization items, net and income taxes	$ 24	$ (86)	$ 110

Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ 73	$ 128	$ (55)
Contracted and capacity	90	87	3
Realized value of hedges	26	65	(39)
Total realized gross margin	189	280	(91)
Unrealized gross margin	(10)	(43)	33
Total gross margin	$ 179	$ 237	$ (58)

The decrease of $91 million in realized gross margin was principally a result of the following:

a decrease of $55 million in energy, primarily as a result of the shutdown of the Lovett facility, lower generation volumes and increased fuel costs, partially offset by higher power prices; and

a decrease of $39 million in realized value of hedges for our generation output, as a result of a decrease in the amount by which the settlement value of power contracts exceeded market prices and lower volumes hedged in 2008, partially offset by an increase in the settlement value of fuel contracts.

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The increase of $33 million in unrealized gross margin was comprised of unrealized losses of $10 million in 2008 compared to $43 million in 2007. The unrealized losses were related to the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and decreases in value associated with forward power and fuel contracts for future periods primarily as a result of increases in forward power prices.

Operating Expenses

The decrease of $174 million in operating expenses was principally the result of the following:

- a decrease of $175 million as a result of the impairment loss on our Lovett facility recognized in the second quarter of 2007. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to this impairment;

- a decrease of $12 million in operations and maintenance expense primarily related to the Lovett facility, which includes a decrease of $33 million in operating costs, partially offset by $17 million of shutdown costs at the Lovett facility incurred in 2008. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to the shutdown of the Lovett facility; and

- a decrease of $19 million in gain on sales of assets. In 2008, subsidiaries in our Northeast segment recognized a gain of $30 million, of which $24 million related to emissions allowances sold to third parties. In 2007, subsidiaries in our Northeast segment recognized a gain of $49 million which includes a $14 million gain on the sale of certain ancillary equipment included in the sale of the six U.S. natural gas-fired facilities and a $33 million gain on the sales of emissions allowances, of which $11 million related to emissions allowances sold to Mirant Mid-Atlantic that are eliminated in our consolidated statement of operations.

California

Our California segment consists of the Contra Costa, Pittsburg and Potrero facilities with total net generating capacity of 2,347 MW.

The following tables summarize the results of operations of our California segment (in millions):

	Years Ended December 31,		Increase/
	2008	2007	(Decrease)
Realized gross margin	$ 127	$ 135	$ (8)
Unrealized gross margin			
Total gross margin	127	135	(8)
Operating Expenses:			
Operations and maintenance	76	74	2
Depreciation and amortization	23	13	10
Gain on sales of assets, net	(7)	(2)	(5)
Total operating expenses	92	85	7
Operating income	35	50	(15)
Total other expense (income), net	1	(5)	6
Income from continuing operations before reorganization items, net and income taxes	$ 34	$ 55	$ (21)

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Gross Margin

	Years Ended December 31,		Increase/
	2008	2007	(Decrease)
Energy	$ 4	$ 3	$ 1
Contracted and capacity	123	132	(9)
Total realized gross margin	127	135	(8)
Unrealized gross margin			
Total gross margin	$ 127	$ 135	$ (8)

The decrease of $9 million in contracted and capacity includes a $3 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008 and extended outages at unit 3 of the Potrero generating facility in the first quarter of 2008.

Operating Expenses

The increase of $7 million in operating expenses was principally the result of higher development costs and higher depreciation expense in 2008, partially offset by lower maintenance expenses and an increase in gains on sales of assets, net primarily as a result of the sales of emissions allowances in 2008.

Other Operations

Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances. For the year ended December 31, 2007, Other Operations also included gains and losses related to the Back-to-Back Agreement, which was terminated pursuant to a settlement that became effective in the third quarter of 2007. See Pepco Litigation in Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Back-to-Back Agreement.

The following tables summarize the results of operations of our Other Operations segment (in millions):

	Years Ended December 31,		Increase/
	2008	2007	(Decrease)
Realized gross margin	$ (17)	$ 126	$ (143)
Unrealized gross margin	120	(14)	134
Total gross margin	103	112	(9)
Operating Expenses:			
Operations and maintenance	28	94	(66)
Depreciation and amortization	10	10	
Gain on sales of assets, net	(2)	(5)	3
Total operating expenses	36	99	(63)
Operating income	67	13	54
Total other expense (income), net	123	(282)	405
Income (loss) from continuing operations before reorganization items, net and income taxes	$ (56)	$ 295	$ (351)

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Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ (17)	$ 109	$ (126)
Contracted and capacity		17	(17)
Total realized gross margin	(17)	126	(143)
Unrealized gross margin	120	(14)	134
Total gross margin	$ 103	$ 112	$ (9)

The decrease of $143 million in realized gross margin was principally a result of the following:

- a decrease of $126 million in energy, comprised of a $83 million decrease from fuel oil management activities, a $37 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008 and a $6 million decrease from proprietary trading activities. The significant decrease in the contribution from fuel oil management activities primarily relates to the timing of the settlement of contracts used to hedge the fair value of fuel oil inventory compared to the timing of the use or sale of the fuel oil; and

- a decrease of $17 million in contracted and capacity resulting from the termination of the Back-to-Back Agreement in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for additional information related to the Pepco Settlement Agreement.

The increase of $134 million in unrealized gross margin was comprised of the following:

- unrealized gains of $120 million in 2008, which include a $65 million net increase in the value of contracts for future periods primarily related to changes in forward power prices in 2008 and an increase of $55 million from power and fuel contracts that settled during the period for which net unrealized losses had been recorded in prior periods; and

- unrealized losses of $14 million in 2007, including:

  - $102 million of unrealized losses related to proprietary trading and fuel oil management activities which include $115 million from the settlement of power and fuel contracts during the year for which unrealized gains had been recorded in prior periods and a $13 million net increase in value associated with contracts for future periods; partially offset by

  - $88 million of unrealized gains on the Back-to-Back Agreement and related hedges. The Back-to-Back Agreement was terminated in the third quarter of 2007.

Operating Expenses

The decrease of $63 million in operating expenses was primarily a result of a decrease of $66 million in operations and maintenance expense, which include:

a decrease of $32 million resulting from the 2007 increase in our estimated obligation to MC Asset Recovery under the Plan. See Note 16 to our consolidated financial statements contained elsewhere in this report for additional information related to MC Asset Recovery;

a decrease of $26 million related to corporate overhead costs included in Other Operations in 2007 but allocated across Mirant s operating segments in 2008;

a decrease of $16 million related to the 2007 bonus plan for dispositions;

a decrease of $9 million related to litigation contingencies; partially offset by

an increase of $27 million related to a decrease in curtailment gains on pension and postretirement benefits reflected as a reduction of operations and maintenance expense.

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Other Expense (Income), Net

Other expense (income), net decreased $405 million primarily as a result of the following:

- a decrease in other, net of $348 million, which includes a gain of $341 million in 2007 resulting from the termination of the Back-to-Back Agreement and a gain of $2 million for the refund of excess proceeds from the sales of shares distributed to Pepco, both as a result of the Pepco Settlement Agreement becoming fully effective. See Note 17 to our consolidated financial statements contained elsewhere in this report for additional information related to the Pepco Settlement Agreement;

- a decrease of $130 million in interest income primarily related to lower average cash balances and lower interest rates on invested cash; partially offset by

- a decrease of $73 million in interest expense related to lower debt outstanding and higher interest capitalized on construction projects in 2008.

Other Significant Consolidated Statements of Operations Comparison

Discontinued Operations

For the year ended December 31, 2008, income from discontinued operations was $50 million and included insurance recoveries related to the Sual generating facility outages that occurred prior to the sale.

For the year ended December 31, 2007, income from discontinued operations was $1.562 billion and included:

- a pre-tax gain of $2.003 billion on the sale of the Philippine business, a pre-tax gain of $63 million on the sale of the Caribbean business, a reduction to the previous impairment of six U.S. natural gas-fired facilities of $30 million and a gain of $8 million on the sale of Mirant NY-Gen; partially offset by

- an income tax provision of $704 million related to the sale of the Philippine business; and

- operating results for the discontinued operations.

See Note 11 to our consolidated financial statements contained elsewhere in this report for additional information related to the dispositions and discontinued operations.

2007 versus 2006

Gross Margin Overview

The following table details realized and unrealized gross margin by operating segment (in millions):

	Years Ended December 31,					
	2007			2006		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Mid-Atlantic	$ 1,084	$ (479)	$ 605	$ 834	$ 484	$ 1,318

Northeast	280	(43)	237	286	61	347
California	135		135	112	3	115
Other Operations	126	(14)	112	11	107	118
Eliminations	18		18	38		38
Total	$ 1,643	$ (536)	$ 1,107	$ 1,281	$ 655	$ 1,936

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Gross margin for the years ended December 31, 2007 and 2006, is further detailed as follows (in millions):

	Year Ended December 31, 2007					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 686	$ 128	$ 3	$ 109	$ 18	$ 944
Contracted and capacity	196	87	132	17		432
Realized value of hedges	202	65				267
Total realized gross margin	1,084	280	135	126	18	1,643
Unrealized gross margin	(479)	(43)		(14)		(536)
Total Gross Margin	$ 605	$ 237	$ 135	$ 112	$ 18	$ 1,107

	Year Ended December 31, 2006					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 532	$ 117	$ 14	$ 71	$ 38	$ 772
Contracted and capacity	39	44	101	(60)		124
Realized value of hedges	263	125	(3)			385
Total realized gross margin	834	286	112	11	38	1,281
Unrealized gross margin	484	61	3	107		655
Total Gross Margin	$ 1,318	$ 347	$ 115	$ 118	$ 38	$ 1,936

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

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts, through tolling agreements and from ancillary services. For the years ended December 31, 2007 and 2006, contracted and capacity also included the Back-to-Back Agreement, which was terminated on August 10, 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

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

Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts that are recorded as derivative contract assets and liabilities on our consolidated balance sheets, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Our gross margin for the year ended December 31, 2007, was $1.107 billion as compared to $1.936 billion for the same period in 2006. The decrease in gross margin, which includes net unrealized gains and losses from our hedging activities, was principally a result of the following:

A decrease of $1.191 billion in unrealized gross margin was comprised of the following:

- unrealized losses of $536 million in 2007, which include $438 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $98 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007; and unrealized gains of $655 million in 2006, which include a $433 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power prices in 2006 and $222 million from the settlement of power and fuel contracts during the period for which net unrealized losses had been recorded in prior periods.

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An increase of $362 million in realized gross margin primarily attributable to:

- an increase in contracted and capacity of $308 million, which includes the refund by Pepco of $36 million of payments made to it under the Back-to-Back Agreement for periods after May 31, 2006, as a result of the Settlement Agreement with Pepco becoming fully effective in August 2007;

- an increase in energy of $172 million as a result of an increase in power prices, a decrease in emissions prices, slightly higher generation volumes and the settlement of favorable fuel oil management positions; partially offset by

- a decrease of $118 million in incremental realized value of hedges.

Mid-Atlantic

Our Mid-Atlantic segment, which accounts for approximately half of our net generating capacity, includes four generating facilities with total net generating capacity of 5,230 MW.

The following tables summarize the results of operations of our Mid-Atlantic segment (in millions):

	Years Ended December 31,		Increase/
	2007	**2006**	**(Decrease)**
Realized gross margin	$ 1,084	$ 834	$ 250
Unrealized gross margin	(479)	484	(963)
Total gross margin	605	1,318	(713)
Operating Expenses:			
Operations and maintenance	360	333	27
Depreciation and amortization	81	74	7
Gain on sales of assets, net		(7)	7
Total operating expenses	441	400	41
Operating income	164	918	(754)
Total other expense (income), net	(5)	(4)	(1)
Income from continuing operations before reorganization items, net and income taxes	$ 169	$ 922	$ (753)